REPORT ON PROCEEDING NO. 800065

ESTIMATES OF ULTIMATE POTENTIAL AND FORECASTS OF ATTAINABLE PRODUCTIVE CAPACITY OF ALBERTA'S CRUDE OIL AND EQUIVALENT

SUPPLEMENTARY REPORT ON

IMPACT OF THE NATIONAL ENERGY PROGRAM, THE FEDERAL BUDGET AND PROVINCIAL GOVERNMENT ANNOUNCEMENTS ON SUPPLY FORECASTS FOR 1980 TO 1990 OF CRUDE OIL AND EQUIVALENT, AND NATURAL GAS

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ENERGY RESOURCES CONSERVATION BOARD
ALBERTA, CANADA

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ENERGY RESOURCES CONSERVATION BOARD
ALBERTA, CANADA

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1 INTRODUCTION

In June 1980 the Energy Resources Conservation Board convened a hearing, Proceeding No. 800065, to assess the ultimate potential and future productive capacity of crude oil and equivalent in Alberta. The Board has completed its assessment of the evidence presented at the hearing and its conclusions and findings are presented as part of this report (ERCB Report 81-B).

On 26 November 1980 The Honourable Merv Leitch, Minister of Energy and Natural Resources, requested the Board to prepare a supplementary assessment of oil supply for the 1980-1990 period, taking into account developments that have occurred since the Board's hearing. In particular, the Minister referred to the federal budget and National Energy Program that were announced on 28 October 1980 and to subsequent announcements by the Government of Alberta. An Order in Council, O.C. 1153/80, was issued under the provisions of Section 24 (1) of The Energy Resources Conservation Act, which requested the Board to inquire into and report on

- the impact that the National Energy Program and budget, announced by the federal government on 28 October 1980, and subsequent announcements including those by the Alberta government respecting oil supply, would have on the forecast of Alberta oil supply as estimated by the Energy Resources Conservation Board on the basis of evidence presented at the June 1980 hearing, and
- the impact that the aforementioned policies and announcements would have on the forecast of gas supply as estimated by the Energy Resources Conservation Board in its Report 79-G[1] (and 80-G[2]).

---

[1] Ultimate Potential for Gas in Alberta. ERCB Report 79-G, November 1979.

[2] Pan-Alberta Gas Ltd. Gas Removal Permit Amendment Decision. ERCB Report 80-G, October 1980.

Copies of the letter dated 26 November 1980 and the Order in Council are included as Appendices I and II.

1.1 DEVELOPMENTS WHICH COULD AFFECT THE BOARD'S SUPPLY FORECAST BASED ON THE JUNE 1980 HEARING

The Board believes that the following developments could affect its supply forecast based on the June 1980 hearing. Since this forecast was made prior to the National Energy Program (NEP), the federal budget and the provincial government announcements, the Board will refer to the report presenting that forecast as the "pre-NEP report".

The National Energy Program

On 28 October 1980 the federal government announced its National Energy Program which is a comprehensive plan involving the establishment of future oil and gas prices, the introduction of new energy taxes, the modification of existing corporate tax structures and the encouragement of substitution of other energy resources for oil.

The Federal Budget

On 28 October 1980 the federal government presented its proposed budget which incorporated the relevant features of the National Energy Program.

Cut-Back in Alberta Oil Production

On 30 October 1980 The Honourable Premier Lougheed announced that the Government of Alberta would cut back oil production on a graduated basis commencing 1 March 1981 reaching 180 000 barrels a day (approximately

30 000 m^3/d)[1] by 1 September 1981 if no prior agreement on prices for oil and gas is reached between the governments of Alberta and Canada. Order in Council O.C. 1078/80 and Alberta Energy and Natural Resources Information Letter 80-15 provide for and explain the cut-back in production.

Deferral of Oil Sands Projects

Subsequent to 28 October 1980, the Alberta government has indicated that oil sands projects other than the two now operating would be held in abeyance until an agreement respecting all hydrocarbon energy sources is reached between Alberta and federal governments.

1.2 THE MANNER IN WHICH RECENT DEVELOPMENTS MIGHT AFFECT FUTURE OIL SUPPLY

The Board recognizes that there is uncertainty as to whether the foregoing programs will be carried out as presently described and for the full period. Changes may be made to the specifics of the announced programs and, depending on developments, some of the actions might not materialize. For the purpose of this assessment, however, the Board has assumed that the NEP, budget provisions and provincial policies recently announced will be pursued in their original form and will apply over the full period 1980-1990.

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[1] The Board's pre-NEP report on Proceeding No. 800065 is presented in SI units and the National Energy Program (EM&R Report EP80-4E) utilizes Imperial units. This supplementary report uses SI units with the equivalent Imperial units shown in brackets for key figures. Scales of both units are included in the figures. The following nominal conversion factors may be used for other conversions. Detailed factors and abbreviations are included in Appendix A-3 of the pre-NEP report included herewith

Nominal Conversion Factors
1 cubic metre = 6.3 barrels of oil
= 35.5 cubic feet of gas

The NEP and budget were announced only a few weeks ago. They are complex and the impact of some parts of the program varies considerably from company to company. In an attempt to assess the overall impact of these policies, the Board has obtained information from representative companies in industry, has carried out independent analyses, and has monitored public announcements of various companies.

Notwithstanding these assessments, the Board emphasizes that it is at this time only possible to make some broad judgements about the probable impact.

As the Board sees it, the recently announced policies of the federal government would affect its previous forecast of oil supply from Alberta, principally through the effect on funds available to the industry, the relative advantages of investing those funds in Alberta as compared to other alternatives and the viability of production operations under the revised financial conditions. The new policies could therefore have an impact on both the expected rate of production from established reserves, and on the discovery and development of new reserves. The policies announced by the government of Alberta would have a direct effect on the supply of crude oil and equivalent excluding synthetic and, as well, on the development of future oil sands synthetic crude projects.

2 OVERVIEW OF FINANCIAL IMPACT

In reaching its conclusions in its pre-NEP report, the Board assumed that favourable policies and economic conditions would foster a high level of industry activity. More specifically, the Board assumed that by the end of the 1980s conventional oil would be priced at about 85 per cent of anticipated world oil prices and that gas would be priced at about 85 per cent of Canadian oil prices in Toronto. World oil prices were assumed to escalate somewhat above the rate of inflation. Tertiary and synthetic oil were expected to receive sufficiently favourable producer netbacks to make these potential sources attractive investment prospects. Revenue from oil and gas sales would be distributed between the province, the producer and the federal government in shares determined by existing tax and royalty legislation. On the basis of these perceptions, the Board had forecast an aggressive pattern of growth throughout the industry in the province.

The recently announced NEP and federal budget will have a major impact on the Board's assumed economic conditions. First of all, gross revenues received by the industry will be significantly lower than those projected by the Board. The NEP oil price schedule provides for a relatively slow advance in prices during the first few years and a substantially faster advance in later years. Nevertheless, the NEP oil price is still significantly less than that forecast by the ERCB by 1990. A comparison of the oil price schedules is shown in the following table.

Comparison of NEP and ERCB (Pre-NEP)
Light-Medium Crude Oil Wellhead Prices[a]

Year	NEP		ERCB(Pre-NEP)	
	$\$/m^3$	\$/bbl	$\$/m^3$	\$/bbl
1981	120	18	130	21
1983	140	22	210	34
1985	190	31	290	46
1987	280	44	360	57
1989	360	58	440	70
1990	410	65	480	76

---

a Rounded figures

The much lower NEP oil prices during the first few years is particularly important in considering gross revenue impacts since this is the period when crude oil and equivalent production (excluding synthetic) is forecast to be greater.

The NEP gas price schedule is designed to provide a significant change in the current relationships between oil and gas prices. NEP prices depart from the historical relationship of around 85 per cent of the oil equivalent price at the Toronto city gate and by 1983 are equivalent to 67 per cent of the oil price. Thus, gross revenue from gas sold in the Canadian market is reduced even more than from oil. A comparison of the gas price forecasts is shown in the following table.

Comparison of ERCB Pre-NEP and
Post-NEP Gas Price Forecasts[a]

Year	Alberta Border Price for Canadian Sales				Export Price	
	Pre-NEP		Post-NEP			
	$\$/10^3m^3$	$/Mcf	$\$/10^3m^3$	$/Mcf	$\$/10^3m^3$	$/Mcf
1981	90	2.50	60	1.75	230	6.50
1983	150	4.00	80	2.25	330	9.25
1985	210	5.75	110	3.00	400	11.25
1987	270	7.50	160	4.50	470	13.25
1989	340	9.50	220	6.00	550	15.50
1990	380	10.75	270	7.50	600	17.00

[a] Rounded figures

The Board estimates that the NEP oil and gas price schedules will result in gross revenues that are about 20 to 30 per cent less than would have occurred under the Board's pre-NEP price forecasts.

The second impact of the NEP and federal budget on the economic regimes assumed by the Board, stems from the changes in tax legislation. New energy taxes have been introduced as well as changes in corporate income tax provisions. The new Petroleum and Gas Revenue Tax (PGRT) will apply to gross revenue before deduction of royalties but after deduction of certain operating costs and has initially been set at 8 per cent. Since this tax will not be considered as an expense for income tax purposes, its impact on a cash flow or net revenue basis is substantially greater. Its impact will vary somewhat depending on the type of producing operations carried out by a company but the Board estimates that it will reduce cash flow to the industry by not less than 12 per cent.

The changes in corporate income tax are much more difficult to assess since they are designed to reduce incentives to some companies and for provincial lands, while increasing them to other companies and for "Canada Lands". Changes have also been made reducing the allowances made for certain exploration and development costs for income tax purposes. While in certain specific instances the new system may provide increased incentives for exploration in Alberta, the Board believes the overall impact will be to significantly reduce the incentives.

The announced cut-back of oil supply by the Government of Alberta will also have a significant impact on revenues to the industry. The Board estimates that the overall reduction in gross revenue due to the cut-back will be about 10 per cent, being somewhat less in the early years and greater later on.

Not only do the foregoing policies significantly reduce the industry cash flow and the attractiveness of exploration and development prospects in Alberta but they also alter the balance of the relative attractiveness of provincial exploration vis-a-vis exploration in the United States and in "Canada Lands". Much higher oil and gas prices in the United States coupled with what appears to be a more favourable tax and royalty regime may more than compensate for any less favourable geological prospects. Recent announcements by several companies appear to bear out this general conclusion.

The Board's overall conclusion is that the recently announced policies will result in a substantial downturn in exploration and development activity in the province. Over the ten-year period, the Board expects that drilling activity will be 25 per cent lower than had been assumed in its pre-NEP forecast with commensurate effects on reserves additions for both oil and gas.

3 IMPACT ON CRUDE OIL AND EQUIVALENT SUPPLIES 1980-1990

3.1 CRUDE OIL AND EQUIVALENT EXCLUDING SYNTHETIC

3.1.1 Established Reserves

In assessing the impact of the NEP and federal budget on the production from currently established reserves, the Board sought the views of industry on specific matters and made some broad independent analyses. It was evident from the survey that in certain pools (such as the Beaverhill Lake pools) some infill wells, major reworks and installation of water-handling facilities will be required to maintain productivity and that many of these expenditures will not be made under the new provisions. On this basis, the productive capacity of established reserves over the next few years will be less than the Board had forecast earlier.

The Board's own assessment suggests that two factors under the new program could affect its previous projection. The first factor is the NEP oil price schedule which holds back major increases until after 1983. This may lead industry to defer expenditures for workovers, infill drilling, etc., until the higher prices come into effect. This in turn would cause some deferral of production in the early forecast period which might be offset by slightly greater production capability later on.

The NEP oil price schedule must also be considered in relation to future operating costs. At its June 1980 hearing the Board received evidence from industry that unit operating costs are increasing rapidly. As the Board notes in its pre-NEP report "A major share of the oil production in the province derives from reservoirs discovered before 1965". Production from these pools is declining while lifting and water treatment costs are increasing. The overall unit operating costs are therefore rising significantly faster than the rate of inflation and this trend will continue in the future. The Board is not satisfied that the estimates of lifting costs included in the National Energy Program fully recongize this phenomenon. For example the NEP report shows operating costs per barrel of oil produced doubling from 1980 to 1985 whereas the Board expects the unit costs to triple or even quadruple in the same period. The combination of the restricted price increases under the NEP and the rapidly increasing unit operating costs is, in the Board's view, likely to result in some wells becoming uneconomic at an earlier date.

A second factor which the Board believes could influence the supply from currently established reserves, is the decrease of perhaps a third in the cash flow available to industry relative to what the Board had assumed in its pre-NEP report. Accepting the premise that investment alternatives are considered in terms of their relative merits, this reduction in available funds most likely will result in the cancellation of those production maintenance programs that were previously thought marginally profitable. This effect also would result in a somewhat reduced productive capacity in some pools.

Having regard for the results of the industry survey and its own analyses, the Board concludes that the supply of oil from currently established reserves under the NEP and federal budget will be somewhat less than it previously projected. However, because of the many uncertainties, it is not possible at this time to adequately quantify the reduction.

3.1.2 Discoveries/Additions

The rate of growth of reserves through discoveries/additions is to a considerable extent a function of overall drilling activity in the province. The substantial reduction in cash flow to the industry, the reduced attractiveness of many exploration and development projects in Alberta relative to those in the "Canada Lands" or in the United States is likely to lead to a major decline in drilling activity. It is not possible at this time to accurately estimate the extent of the decline although early evidence is already at hand. Survey results, reports of company programs and the various predictions that have appeared in the press provide some general guidance. Having regard for these reports and the other analyses it appears that a decline in drilling activity of 25 per cent, relative to what was previously expected over the ten-year period, will occur under the new programs. The Board has therefore reduced its previous forecast of oil supply from discoveries/ additions, 4000 m^3/d (25 000 bbl/d) by 1985 and 6000 m^3/d (38 000 bbl/d) by 1990.

3.1.3 Tertiary and Pentanes Plus

The Board recognizes that the NEP appears to give incentives to tertiary recovery schemes, however, revisions in existing tax provisions and application of the PGRT may substantially nullify the incentives. In any event, owing to the long lead-time for completion of pilot tests and the characteristically slow production response, particularly of the light-medium tertiary projects, the tertiary production shown in the pre-NEP report during the period 1980 to 1990 is small and need not be changed. While the tertiary incentives appear significant in the near term for heavy crude oil, the price advantage relative to conventional operations will likely be gone by the time the technology is fully developed to insure sustained economically viable tertiary operations.

The new programs will substantially reduce the discoveries/additions to gas reserves, as discussed in Section 4, but since there is already a large surplus, gas production expected during this decade will not be significantly affected. Consequently, since pentanes plus is a co-product of gas production, the NEP would not have a significant effect on the Board's forecast of pentanes plus production over this decade.

3.1.4 Total Oil and Equivalent Supply Excluding Synthetic

As discussed in the preceeding sections, the impact of the NEP and federal budget on total supplies of Alberta crude oil and equivalent excluding synthetic emerges as a composite of somewhat divergent effects.

The impact on tertiary oil and pentanes plus production over the period to 1990 is likely to be negligible. However, the previously projected rates of discoveries/additions will be quite seriously affected and some reduction in production from established reserves also will occur. In

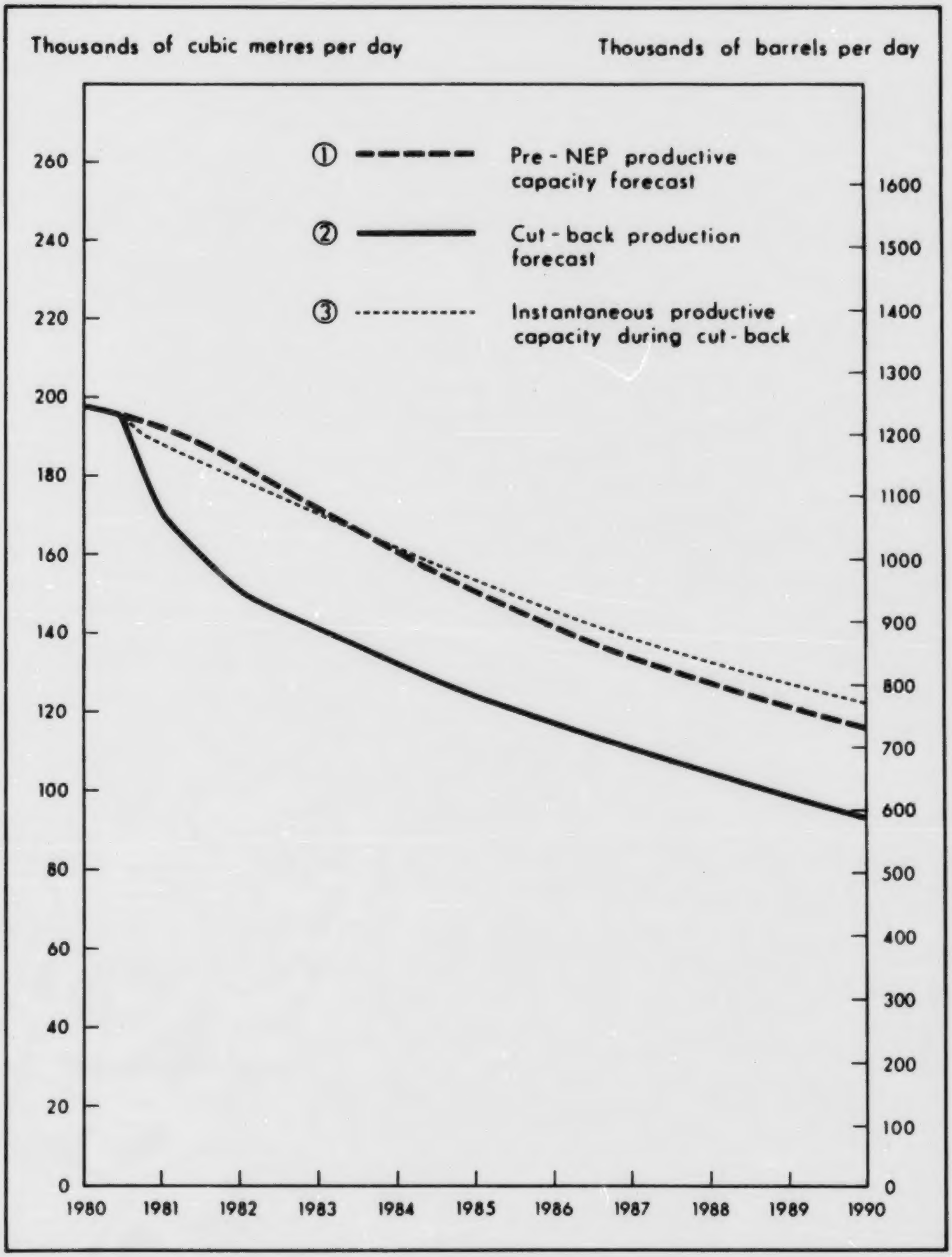

FIGURE S-1 EFFECT OF NEP AND ANNOUNCED CUT - BACK ON FORECAST PRODUCTION OF CRUDE OIL AND EQUIVALENT EXCLUDING SYNTHETIC - ALBERTA the Board's view the gap between pre-NEP and post-NEP potential supply from all sources excluding synthetic would be in the order of 6000 to 8000 m^3/d (40 000 to 50 000 bbl/d).

The cut-back in production announced by the Government of Alberta in October 1980 would reduce light-medium oil production by 30 000 m^3/d (180 000 bbl/d) by 1 September 1981. The cut-back is assumed to apply each year of the full period against the instantaneous productivity determined for the particular year.

The combined impact of the NEP, the budget and the production cut-back is summarized in Figure S-1 where Curve 1 shows the Board's pre-NEP production (productive capacity) forecast for crude oil other than synthetic, Curve 2 shows the forecast of production under the combined impact of the NEP and the cut-back, and Curve 3 shows the forecast "instantaneous" productive capacity that would exist at any time during the cut-back to 1990. The figures show that production of crude oil other than synthetic, is reduced by about 25 000 m^3/d (160 000 bbl/d) through the ten-year period.

3.2 SYNTHETIC CRUDE OIL SUPPLY

The Board's pre-NEP projections of synthetic crude oil production for the period 1980 to 1990 reflect the expansion now being installed at the Suncor plant, the anticipated expansion of the Syncrude operation, and production from the Alsands and Esso projects commencing in 1987 and reaching full capacity by 1990. In aggregate, these developments would increase synthetic crude oil production from some 21 thousand m^3/d in 1980 to approximately 81 thousand m^3/d by 1990. In view of the announcement by the Alberta government that these oil sands projects would be held in abeyance pending conclusion of an overall energy package agreement and, as well, the recent announcements by Alsands and Esso that the projects are not economically viable under the NEP policies, the Board has assumed that the Syncrude expansion, and the Alsands and Esso projects would not proceed. On this basis, synthetic crude oil production including production from experimental operations would stabilize at 34 thousand m^3/d through 1990. The pre-NEP and post-NEP projections of synthetic crude oil production are shown in Figure S-2.

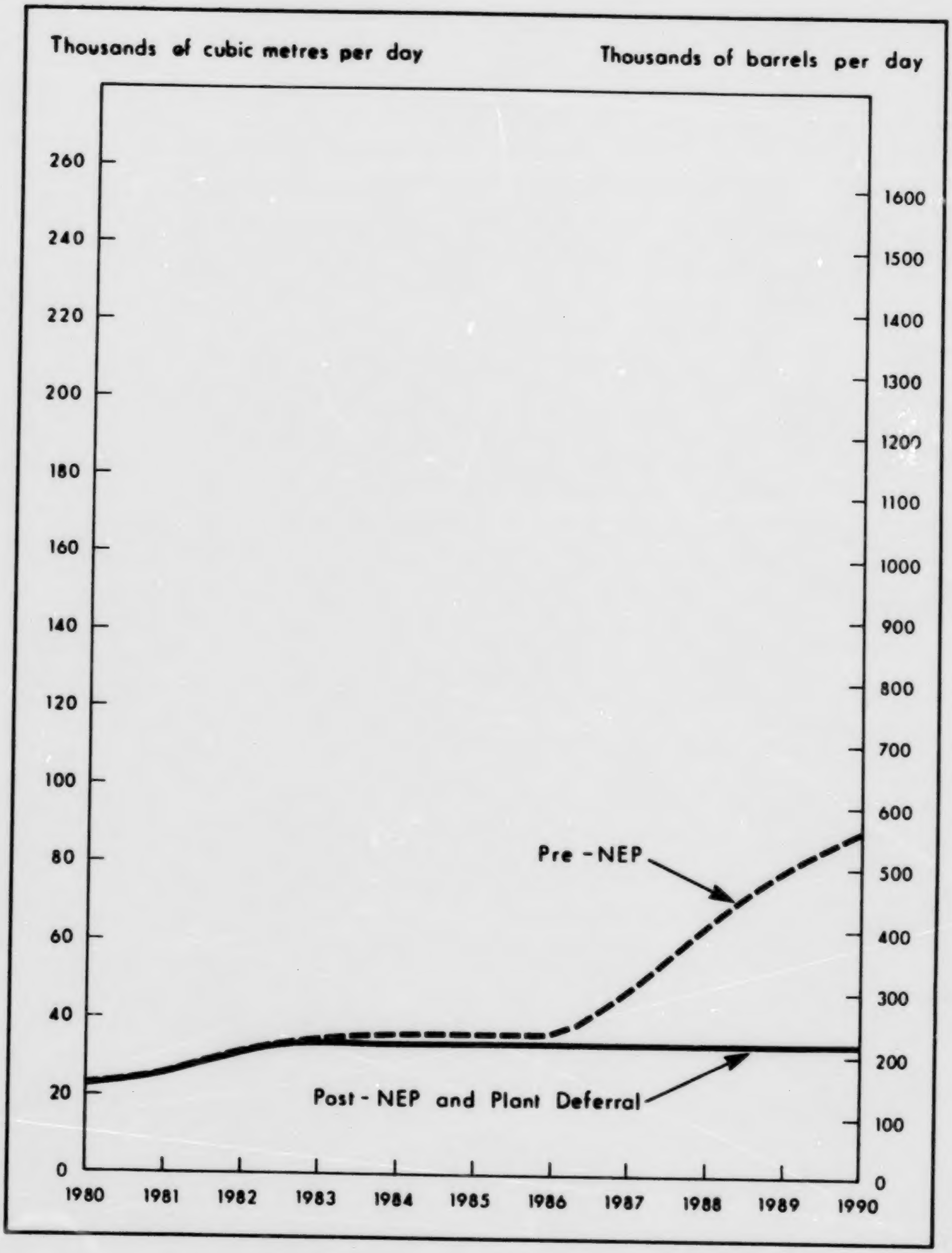

FIGURE S-2 EFFECT OF NEP AND DEFERMENT OF PLANT APPROVALS ON FORECAST PRODUCTION OF BITUMEN SYNTHETIC CRUDE OIL - ALBERTA

3.3 TOTAL CRUDE OIL AND EQUIVALENT SUPPLY 1980-1990

The combined impact of the NEP, the federal budget and announcements by the Alberta Government on the forecast of Alberta's oil supply during the 1980-1990 period is shown in Figure S-3.

As indicated in Figure S-3, the production of crude oil and equivalent from all sources is reduced from the pre-NEP forecast by about 30 000 m^3/d (180 000 bbl/d) in the early part of the decade and, with the deferral of further oil sands synthetic crude projects, the reduction reaches 75 000 m^3/d (470 000 bbl/d) at the end of the decade.

The Board emphasizes that this assessment has been made on the basis of the programs as defined in the initial announcements and on the assumption that they will remain in effect for the full period.

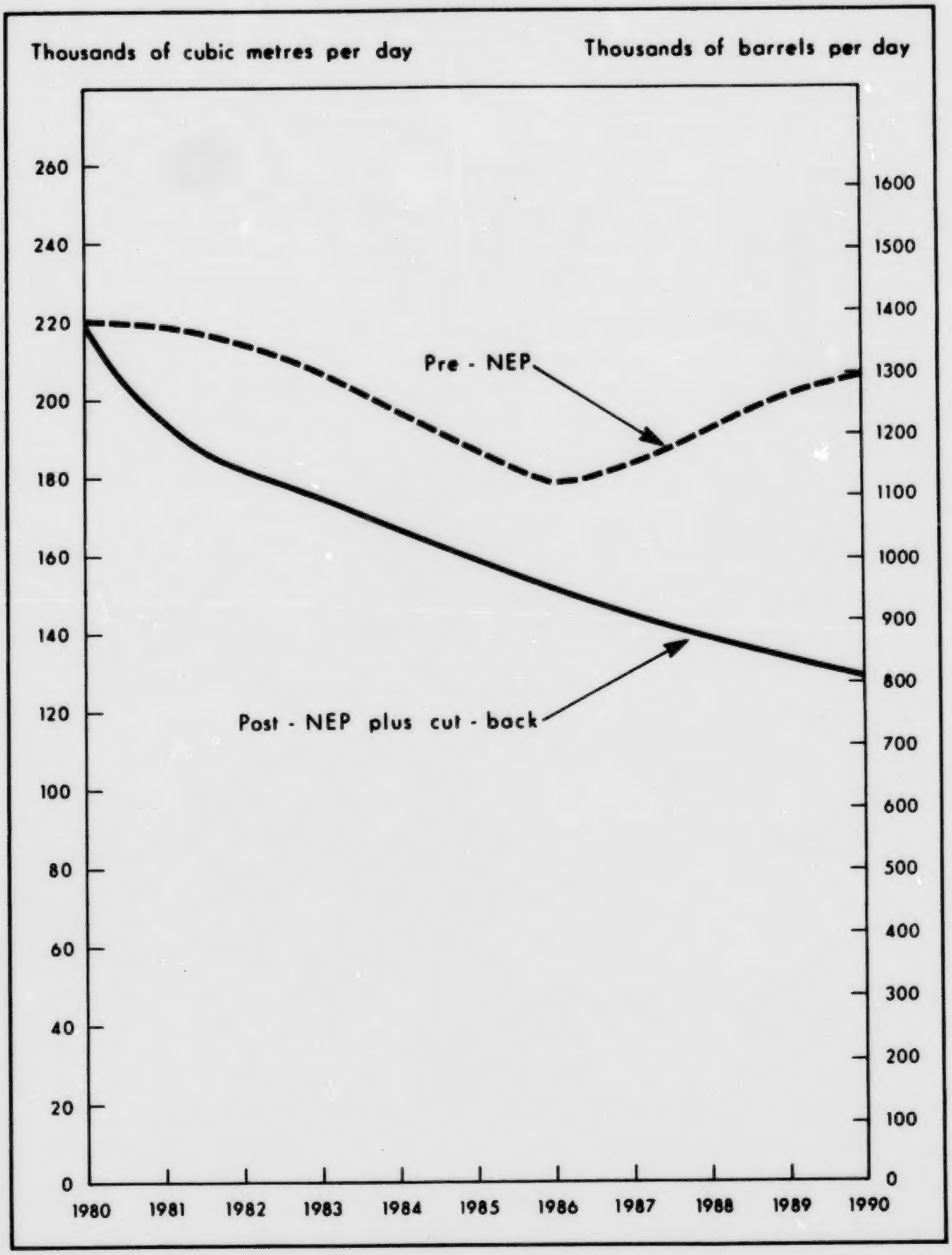

FIGURE S-3 EFFECT OF NEP AND CUT-BACK ON FORECAST TOTAL PRODUCTION OF CRUDE OIL AND EQUIVALENT - ALL ALBERTA SOURCES

4 IMPACT ON GAS SUPPLY 1980-1990

The NEP and federal budget can be expected to have an impact on gas supply similar to that identified in previous sections for crude oil and equivalent. There are, however, some features of the program that result in a more serious impact on gas. For example, the NEP price structure for gas results in the price of gas sold to Canadian markets increasing less rapidly than the price of oil. In addition, since export prices are established by competition from other energy suppliers in the export market, the natural gas tax, which begins at 30 cents per Mcf ($10.65 per 10^3m^3) and escalates rapidly, will be reflected in reduced returns to the producers and the producing provinces. Changes in income tax provisions, particularly respecting qualification of wells as exploratory wells, also have a negative impact on the economics of gas exploration and development.

In ERCB report 80-G, the Board forecast the potential productive capacity for gas in Alberta. In making that forecast the Board assumed that economic conditions would continue to be favorable and that market growth would be sufficient to sustain industry's aggressive exploration and development program. The Board believes that the NEP and federal budget will have a significant impact on economic incentives, and consequently on exploration and development. As discussed previously, drilling activity in the province is expected to decline significantly and with the present gas surplus and the serious reductions expected in producer revenue and cash flow, the Board expects a serious retardation in the discovery and development of gas reserves. In considering the overall effect on gas productive capacity, the Board has applied the same general assumption that it adopted for oil; namely, that the productive capacity from gas discoveries and additions would be reduced by a minimum of 25 per cent.

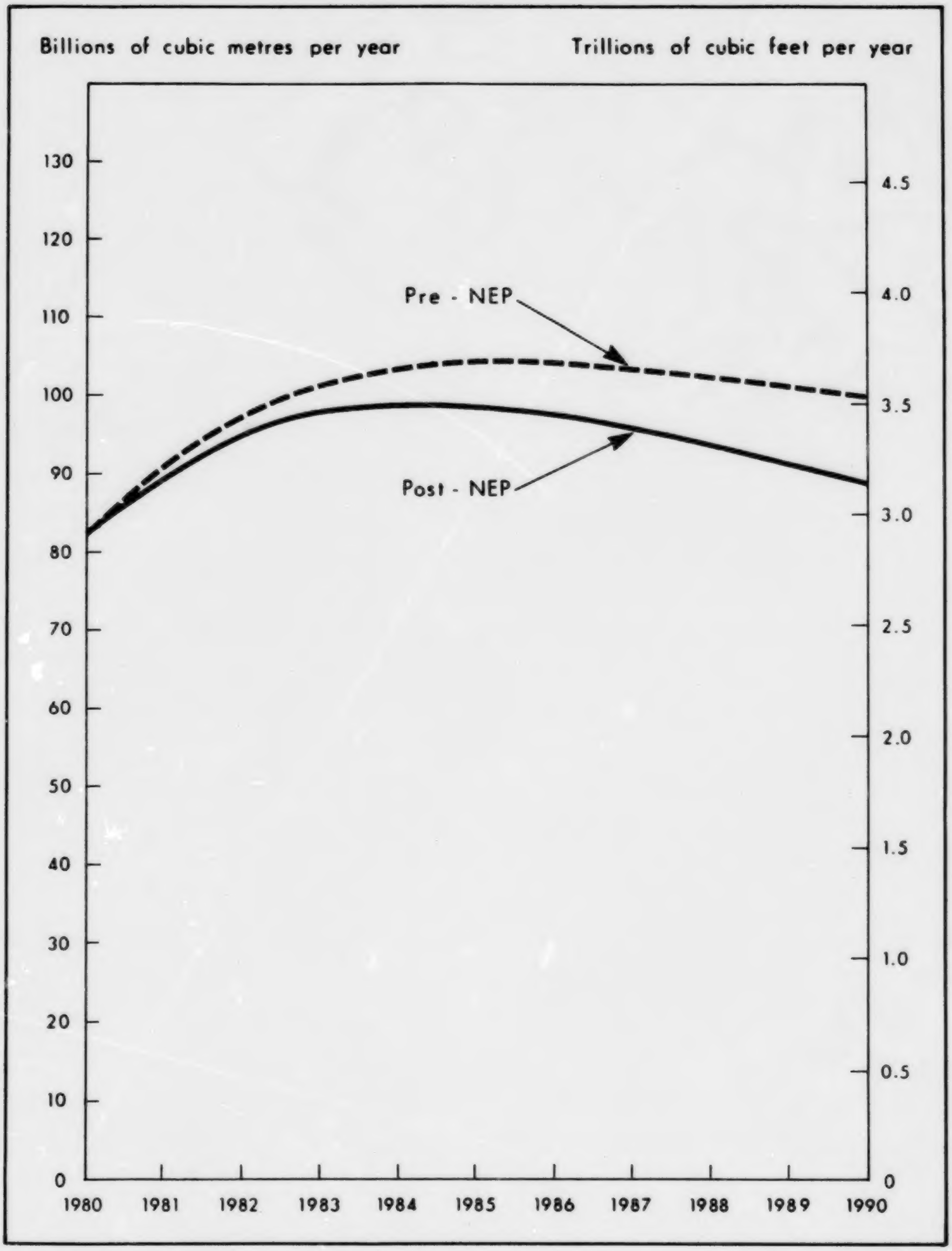

FIGURE S-4 EFFECT OF NEP ON PRODUCTIVE CAPACITY OF NATURAL GAS – ALBERTA

Figure S-4 shows the total potential productive capacity forecast in ERCB Report 80-G and the Board's estimate of the impact of the NEP and federal budget on that forecast. Although the NEP promotes the substitution of gas for oil in Canada, it may also have a compensating effect by reducing the amount considered surplus and available for export. Therefore, since there is currently a large gas surplus in Alberta, the reduction in productive capacity would not significantly affect the forecast of gas production for this decade.

APPENDIX I

S-19

ENERGY AND NATURAL
RESOURCES

Office of
the Minister

403/427-3740

407 Legislative Building
Edmonton, Alberta, Canada
T5K 2B6

November 26, 1980

Mr. V. Millard
Chairman
Energy Resources Conservation Board
604 - 5th Avenue S.W.
CALGARY, Alberta
T2P 3G4

Dear Mr. Millard:

I understand from our recent conversation that the Board has completed its assessment of the evidence presented last June at its hearing to consider estimates of the ultimate potential and forecasts of productive capacity of Alberta's crude oil and equivalent. You advised that the Board planned to issue its findings on these matters in the immediate future. You also indicated that the forecasts of productive capacity were developed for the twenty year period 1980 to 2000 and were based on favourable economic conditions and policies as well as aggressive development by the industry. I take it, therefore, that the forecast of oil supply that the Board has developed represents what could occur under completely favourable circumstances.

The Board's findings on these matters will be of considerable interest to the government and I expect to the industry and general public. I believe their value could be considerably increased, however, if they were supplemented by an assessment of the impact of recent public announcements. I refer, of course, to the National Energy Program and Budget announced by the federal government on October 28, 1980 and to subsequent announcements by the Alberta Government. I expect that these developments may well have a significant impact on the Board's forecast of oil productive capacity, particularly during the next decade. Furthermore, since exploration activity will undoubtedly be affected, I expect that there will be an impact on previous Board forecasts of gas supply.

. . . 2

In view of the foregoing, I plan to seek, under section 24, subsection (1) of The Energy Resources Conservation Act, the approval of the Lieutenant-Governor in Council that the Board be requested to report on the impact that the recent federal and provincial policy statements would have on Alberta oil and gas supply during the next decade. I believe that it would be most helpful if this supplementary assessment could be made as quickly as possible and its findings incorporated in the Board's decision report on Alberta oil supply.

Yours truly,

Merv Leitch
Minister

APPENDIX II

Alberta
ORDER IN COUNCIL

APPROVED AND ORDERED,

F. Lynch-Staunton
LIEUTENANT GOVERNOR

O.C. 1153/80

December 10, 1980

EDMONTON, ALBERTA

WHEREAS in June, 1980 the Energy Resources Conservation Board convened a public hearing to consider the ultimate potential and productive capacity of Alberta crude oil and pentanes plus, and

WHEREAS the Energy Resources Conservation Board has completed its assessment of the evidence presented at the June hearing and plans to issue its findings in the near future, and

WHEREAS the assessment and findings of the Energy Resources Conservation Board are based on favourable economic conditions and policies, as well as aggressive development by the industry, and

WHEREAS recent announcements including those by the federal and provincial governments indicate that economic conditions and policies will not be as favourable as assumed by the Energy Resources Conservation Board in its assessment:

THEREFORE, upon the recommendation of the Honourable the Minister of Energy and Natural Resources, the Lieutenant Governor in Council, pursuant to section 24(1) of The Energy Resources Conservation Act, requests the Energy Resources Conservation Board to make inquiries into and report on

(a) the impact that the National Energy Program and Budget, announced by the Federal Government on October 28, 1980, and subsequent announcements including those by the Alberta Government respecting oil supply, would have on the forecast of Alberta oil supply as estimated by the Energy Resources Conservation Board on the basis of evidence presented at the June 30, 1980 hearing, and

(b) the impact that the aforementioned policies and announcements would have on the forecast of gas supply as estimated by the Energy Resources Conservation Board in its Report 79-G.

CHAIRMAN

REPORT ON PROCEEDING NO. 800065

ESTIMATES OF ULTIMATE POTENTIAL AND FORECASTS OF ATTAINABLE PRODUCTIVE CAPACITY OF ALBERTA'S CRUDE OIL AND EQUIVALENT

JANUARY 1981

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA, CANADA

ACKNOWLEDGEMENTS

Several members of the Board's staff assisted rather extensively in preparation of this report. Guy Berndtsson co-ordinated the hearing proceedings and the preparation of the report. Richard Funk, Terry Hurst, Jack Bray, Milan Vrskovy and Harvey Halladay provided technical advice. Barry Scott, Les Newman, Elizabeth Parry, Elda Allison, Abe Sawatzky and Carry Tays contributed significantly in compilation and final editing.

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1 SUMMARY - CONCLUSIONS

Proceeding No. 800065, a hearing to consider evidence respecting the ultimate reserves potential and productive capacity for crude oil and equivalent in Alberta over the period 1980 to 1999, was completed on 26 June 1980. The Board has reached conclusions about the ultimate potential and future productive capacity for each of the four current main categories of crude oil and equivalent: light-medium, heavy, pentanes plus and synthetic. However, the Board emphasizes that its conclusions respecting future productive capacity depend on long-term favourable policies and favourable economic conditions.

ULTIMATE POTENTIAL

The following table summarizes the Board's current estimate of ultimate potential for each of the major sources of crude oil and equivalent in Alberta.

(millions of cubic metres)

	Light-Medium	Heavy	Pentanes Plus	Bitumen Synthetic		Total
				Mining	In situ	
Initial Established	1803	87	244	4010	-	6 144
Cumulative Production (79-12-31)	1081	49	119	32	-	1 281
Remaining Established	722	38	125	3978	-	4 863
Discoveries/ Additions	300	40	74	-	-	414
Terti[illegible]	300	75	-	-	-	375
Projected Development	-	-	-	1990	24 000	25 990
Total Initial Potential	2403	202	318	6000	24 000	32 923
Total Remaining Potential (79-12-31)	1322	153	199	5968	24 000	31 642

LIGHT-MEDIUM

The Board estimates that remaining established reserves of light-medium crude oil are some 722 million m^3. Through continued drilling in all areas of the province it is expected that some 300 million m^3 of reserves will be added. Three-quarters of this total, 225 million m^3, will be realized in the next 20 years. The ultimate potential for tertiary recovery is now forecast with a reasonable degree of certainty to be some 300 million m^3 of recoverable reserves in addition to that already recognized for tertiary projects operating in the province. The Board assumes that economic incentives would be such as to foster a strong pace of development of light-medium tertiary oil projects, and that most of the potential will be brought on stream over the next 20 years. In summary, the Board finds that the remaining potential for light-medium crude oil is 1322 million m^3.

HEAVY

Despite growing expectations of heavy crude oil production in recent years, the Board finds little basis for such expectations. The Board finds that the remaining established potential is 38 million m^3 and that some 40 million m^3 of future conventional heavy oil reserves may be added, mostly over the next 20 years. But owing to paucity of field experimental or operating evidence, prospects for tertiary heavy oil recovery, are largely hypothetical. For purposes of this report the Board estimates tertiary heavy oil potential to be 75 million m^3. In summary, the Board estimates the remaining heavy oil potential from all sources to be 153 million m^3, a rather modest amount in comparison to light-medium.

PENTANES PLUS

The potential for pentanes plus bears a direct relation to the forecast for Alberta's ultimate natural gas potential. This was reviewed and reported on in ERCB Report 79-G. In accord with these estimates the Board finds that continued discoveries and additions will combine to add some 74 million m^3 of pentanes plus and thereby provide a remaining potential of 199 million m^3 of that category of crude oil equivalent. The Board expects that, like future light-medium and heavy, the bulk of the future pentanes plus additions will be found in the next 20-year period.

BITUMEN SYNTHETIC CRUDE

The potential for bitumen synthetic crude is extraordinarily large when compared to conventional sources of crude oil and equivalent, but very little of this potential has been developed thus far. However, current commercial mining operations have proved the viability of surface mining exploitation, and considerable field pilot experimentation has tended to demonstrate that extensive in situ recovery operations could be underway within the next 20 years. Therefore, for this report, the Board adopts the estimates recently updated and included in ERCB Report 80-18. From surface mining operations near Fort McMurray, bitumen synthetic crude ultimate potential is estimated to be 6000 million m^3, an amount roughly four times the combined remaining potential for light-medium crude, heavy crude and pentanes plus. For in situ recovery, however, the estimated ultimate potential is conjectural, since there is no sustained large scale commercial production. Subject to that qualification, the Board has estimated the ultimate in situ potential at 24 000 million m^3.

FUTURE PACE OF GROWTH

In order to project future supply pattern of the various sources of crude oil and equivalent, it is necessary to project the pace at which various developments will occur. In the Board's view, development of conventional sources of crude oil and equivalent can be estimated with reasonable certainty, since over three-quarters of the sedimentary basin in Alberta has been extensively explored and developed and drilling is proceeding at a sustained pace. Projections indicate that the bulk of future conventional sources of crude oil and equivalent - light-medium, pentanes plus and heavy - will be found and developed over the next 20 years. The expected development sequence of these conventional sources is shown in Figure 1-1. Non-conventional sources of crude oil and equivalent are comprised of tertiary recovery projects in light-medium and heavy oil reservoirs, and of bitumen synthetic crude projects.

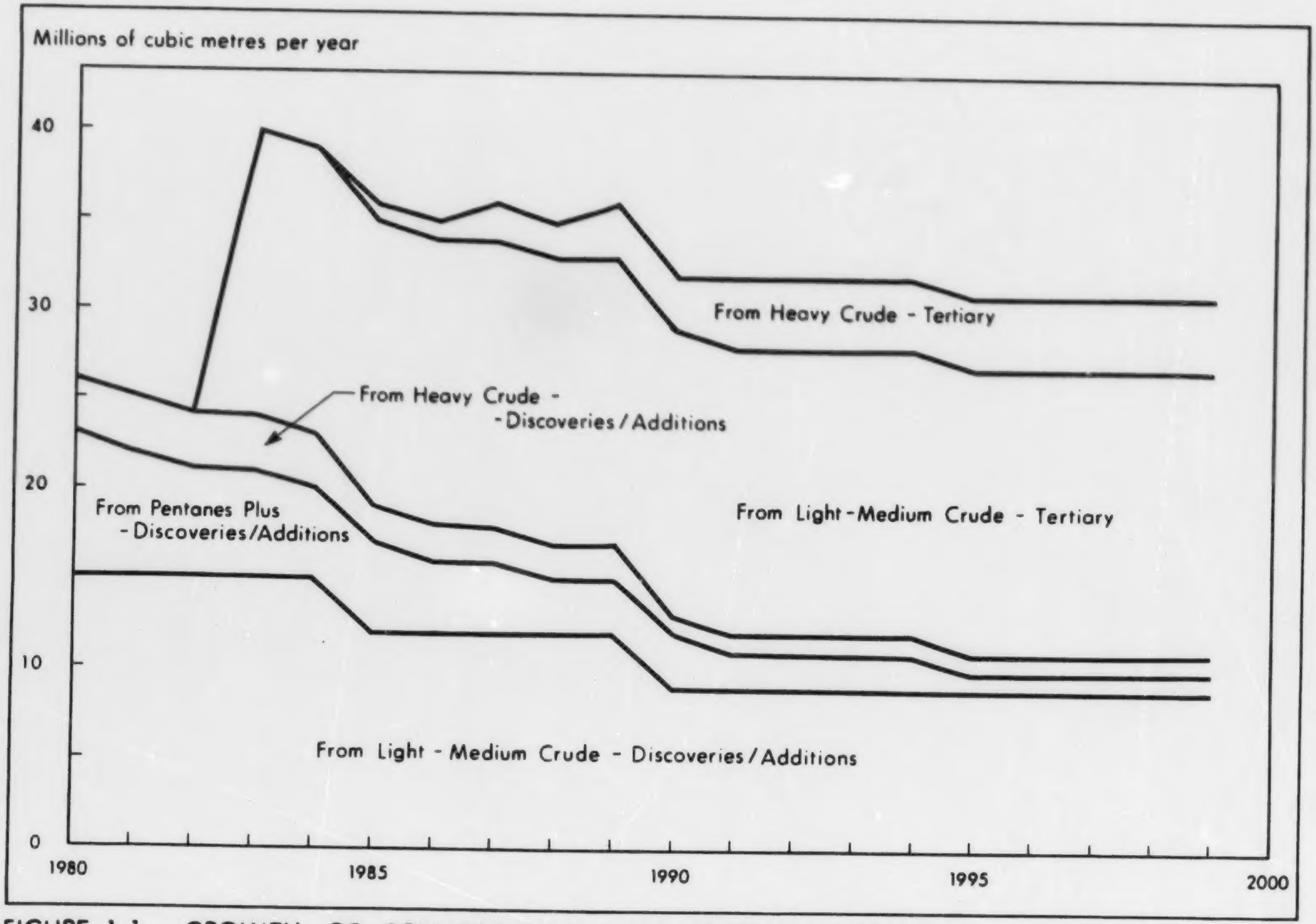

FIGURE 1-1 GROWTH OF CONVENTIONAL AND TERTIARY POTENTIAL

While recognizing that technical, environmental and social factors influence these developments, the overriding factor determining the pace of growth will be the perceived economic return. Under attractive and stable economic policies, a very aggressive pattern of growth for both the tertitary oil sources and the bitumen synthetic crude sources could be anticipated. But given serious uncertainty respecting future economic policies, the development of non-conventional sources of crude oil could be considerably retarded. For purposes of this report, the Board has assumed that the long-term economic climate will be conducive to an aggressive pace of development of non-conventional sources of crude oil, and has therefore "booked" the tertiary reserves in the pattern shown on Figure 1-1. Not included in this diagram are bitumen synthetic sources. The Board recognizes that the size of individual commercial projects for bitumen synthetic crude might vary considerably, and in part depend on future advances in extraction and upgrading technology. For its forecast, the Board has assumed that the Suncor (GCOS), Syncrude (expanded), Esso Cold Lake and Alsands plants would all be operating at capacity by 1990. The Board also assumed that other in situ recovery and mining projects would be under construction in the latter part of the decade leading to mounting annual additions of synthetic crude oil supplies during the 1990s. However, the actual pace of growth could be restrained by availability of project engineering and skilled manpower, development of infrastructure and accommodation of a variety of social and environmental concerns.

In summary the Board finds that projections of conventional sources of supply can be made with a reasonable degree of accuracy, but that projections of non-conventional future sources of supply are subject to a number of qualifications. On the other hand, non-conventional sources represent a very large potential and can be expected to be given the substantial emphasis they deserve in both the near-range and longer-range future.

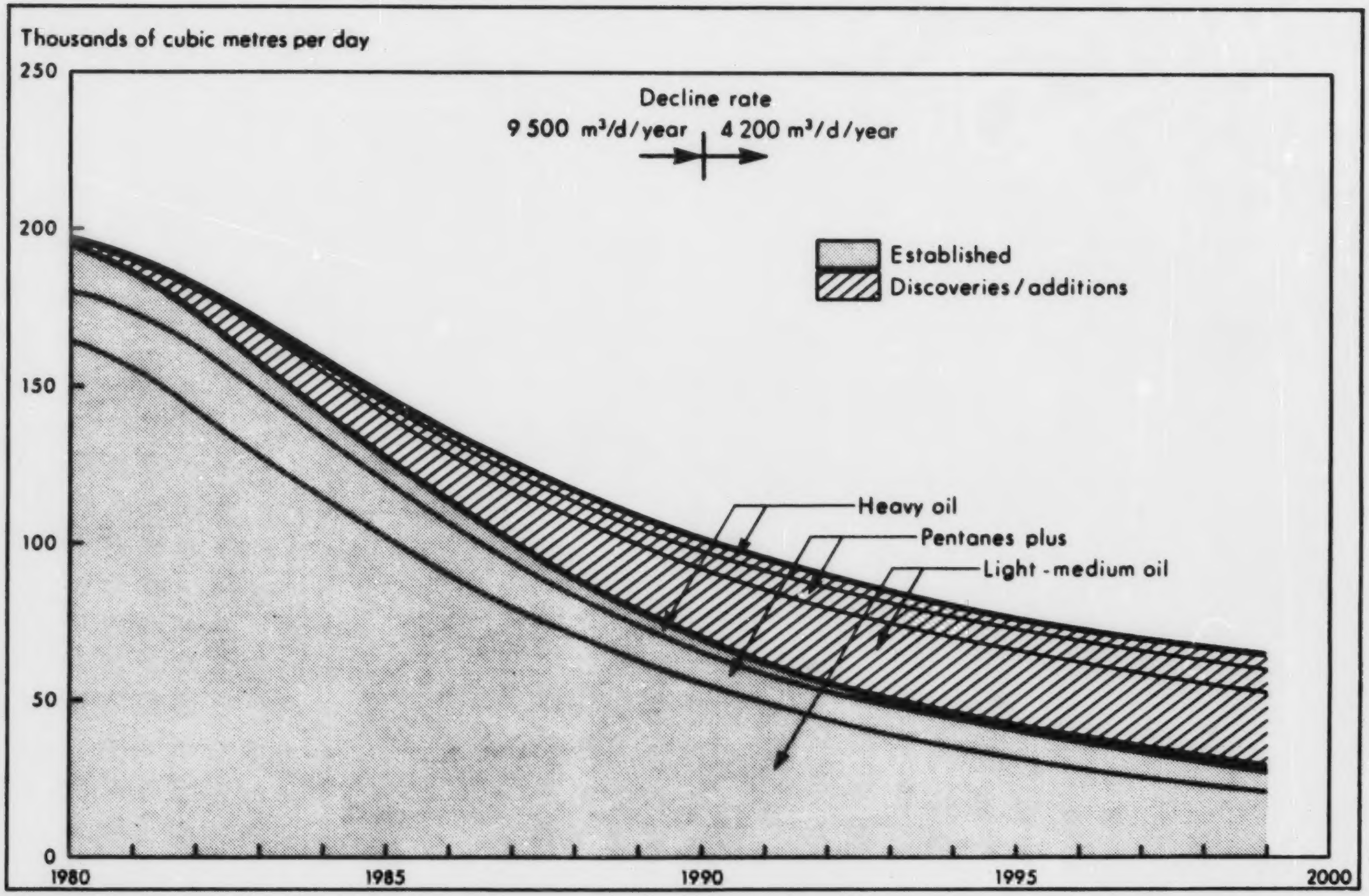

FIGURE 1-2 FORECASTS OF THE DOWNWARD DRIFT OF SUPPLY FROM CONVENTIONAL SOURCES

PRODUCTIVE CAPACITY FORECASTS

Forecasting the productive capacity or, so called supply, of crude oil and equivalent involves detailed consideration of a number of important factors which, as discussed in the preceding section, can influence the pace of development of new supplies and the manner in which the supply sources will tend to drift downward as they are depleted. The Board has concluded that future patterns of supply from each of the four main categories of crude oil and equivalent over the ensuing 20-year period will be more or less as shown below. Light-medium crude supply will continue its already apparent decline through the forecast period and the principal option for offsetting that decline is production of bitumen synthetic crude. To the extent that they can be considered credible and will be fulfilled, the forecasts indicate that synthetic crude production will move from a position of supplying approximately one-tenth of the provincial supply in 1980 to approximately two-thirds of the provincial supply by the year 2000.

Thousands of cubic metres per day

Year	Light-Medium	Pentanes Plus	Heavy	Bitumen Synthetic	Total
1980	166	17	14	23	220
1985	120	20	11	36	187
1990	91	15	10	88	204
1995	75	14	12	128	229
1999	69	14	12	160	255

To give a more complete perspective on future sources of supply, the Board has combined the projections from all conventional sources as shown in Figure 1-2. Since established sources can be projected with a relatively high degree of accuracy and the additional supply from new discoveries and

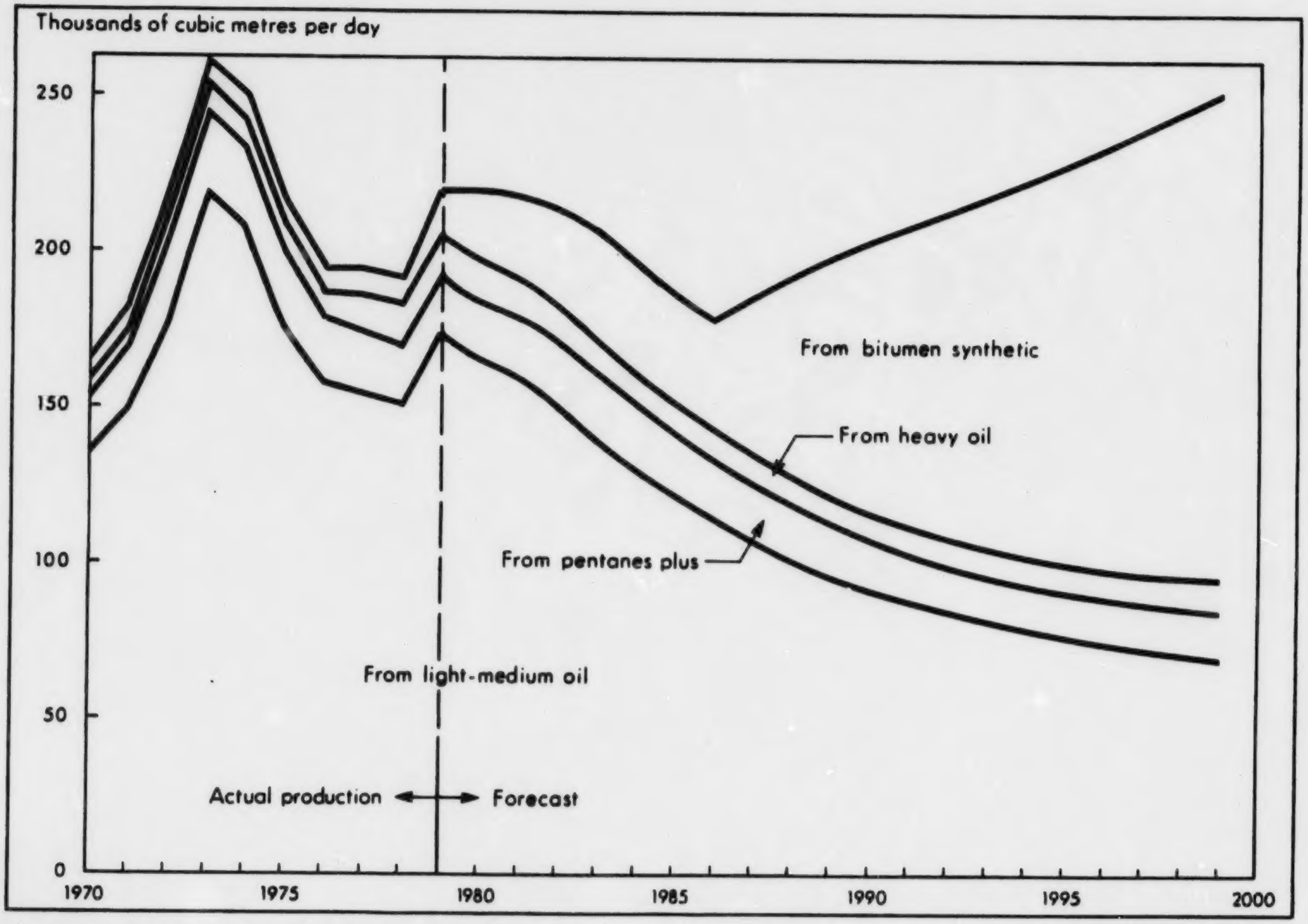

FIGURE 1-3 ERCB PRODUCTIVE CAPACITY OF ALBERTA'S CRUDE OIL AND EQUIVALENT. All sources.

field extentions can also be estimated with reasonable accuracy, the overall decline projections for conventional supplies of crude oil and equivalent are considered fairly reliable. These projections indicate that conventional supplies will decline from the current level of 197 thousand m^3/d in 1980 to 102 thousand m^3/d in 1990, after which the rate of decline will slow and the combined productivity in 1999 would be about 69 thousand m^3/d. The Board has determined that such special measures as infill drilling are unlikely to materially alter this pattern. It appears therefore that non-conventional sources - tertiary recovery projects and bitumen synthetic crude projects - represent the only important sources of supply replenishment which could bolster overall production[1].

The pattern of supply over the past decade and the projection for the next two decades shown on Figure 1-3 indicate that aggressive development of non-conventional sources of supply will slow the overall downward drift of crude oil supplies in the province in the latter part of the 1980s, and that supply could climb back toward current levels by the mid-1990s. The Board stresses, however, that achievement of these production targets will depend critically on perceptions of the long-range outlook for satisfactory economic return from non-conventional sources of crude oil.

OTHER FACTORS IMPORTANT TO FUTURE SUPPLIES

The Board concludes that one of the important considerations in projecting the future pace of development of non-conventional crude oil supply is the lead time required for field demonstration programs and construction of commercial projects. The Board has determined that conventional supplies will decline at a rate of approximately 10 thousand m^3/d per year from 1980 to 1990 and over the ensuing 10-year period will continue to decline at a rate of about 4 thousand m^3/d per year. To offset these declines by development of tertiary and synthetic projects would require capital investments in the order of 200 thousand to 300 thousand $\$/m^3/d$ in 1980 dollars. Moreover, the Board has determined that lead times for such projects - from adoption of the concept, through field demonstration testing to construction and start-up of production - are typically five to ten years. Most evidence indicates that this period cannot be significantly shortened and, if serious problems arise, might in fact be lengthened. With this key consideration in mind, the Board has determined that, even assuming a favourable perception of economic return, an aggressive development scenario and a shortened regulatory review process, only very small amounts of non-conventional oil supply could be brought on stream in the next five years. As a result, it seems certain that overall supplies of crude oil and equivalent in the province are likely to decline by some 50 thousand m^3/d, or nearly one-quarter of current capability, during the first half of this decade. If construction of the Esso Cold Lake and Alsands projects as well as expansion of the Syncrude project were now launched, the downward drift in overall supply could be reversed in the latter part of the decade through the addition of some 55 thousand m^3/d of additional synthetic crude. On the other hand, delays in commencing construction will cause continuing slippage of overall supply at a rate of about 10 thousand m^3/d for each year of delay.

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[1] Consideration of coal liquefaction was not specifically requested in the notice of hearing. However, "direct" coal liquefaction is a potential alternative source of synthetic crude and, having regard for its present stage of development, could conceivably occur in Alberta in the first half of the 1990s.

In accord with its estimates of required capital investments to develop non-conventional sources of oil supply, the Board concludes that annual investments of two to three billion dollars would be required over the next 15-to 20-year period in order to achieve the desired overall level of supply replenishment. The Board also finds that, over this same period, costs of conventional production will likely rise substantially above current levels, due mainly to large increases in the quantities of water that must be lifted and treated in order to sustain conventional production during the latter stages of depletion of the major oil reservoirs. The Board assumes that though these costs may be in the range of 60 to

80 $\$/m^3$ of oil production by 1990, the then prevailing price, tax and royalty structure would be such as to ensure production of those sources. If added lifting costs cannot be accommodated within the prevailing price structure, indefinite shut-in or abandonment might occur. However, increasing costs could be accommodated if current world crude prices were in effect.

FUTURE UPDATES OF FORECAST

The Board plans to update the estimates and forecasts presented in this report as appropriate when new information makes significant changes necessary. This would be particularly appropriate when projects for tertiary and synthetic crude are developed which permit a better definition of those forecasts. The Board expects that, as a rule, major public hearings would not be required for this purpose.

2 INTRODUCTION

2.1 BACKGROUND

The Energy Resources Conservation Board (ERCB) has annually assessed crude oil reserves and productive capacity of the province since the early 1950s. It also periodically has reviewed the ultimate crude oil potential of the province. In both, it has considered submissions from industry and independent studies by the Board staff.

Estimates of productive capacity for part of the period since 1950 were based on approximations, as most pools were seldom operated at or near their productive capacities for any appreciable length of time. However, in recent years, demand for crude oil production from the province increased, while pool depletion has reached a mature stage and, thus, a majority of pools have been operating close to or at their productive capacities. Therefore current estimates and projections of the productive capacity of developed oilfields can now be made with considerable accuracy.

Today, with productive capacity from established reserves clearly on the decline, much consideration is being given to sources that could be exploited in order to replenish supplies. Principal future sources include new discoveries and extensions, tertiary recovery, bitumen synthetic crude and possibly synthetic crude from coal. In view of the significant lead time required to bring most of these sources on stream, assurance of satisfactory economic returns over the long range is a prime prerequisite for launching the necessary developments. This is especially significant in view of the fact that the most attractive prospects of conventional oil in Alberta have already been developed and the non-conventional sources are perceived to involve substantial technical risk.

The ERCB invited submissions on these matters to the hearing in June 1980 and, in this report, presents a summary of the evidence submitted, its assessment of the matters considered and its conclusions respecting future crude oil supplies in the province.

2.2 THE HEARING AND PARTICIPANTS

In the Notice of Hearing for Proceeding No. 800065, dated 8 February 1980, and in Informational Letter IL 80-3 (Appendices A-1 and A-2), the Board invited interested parties to file submissions respecting Alberta's productive capacity and ultimate potential of crude oil and equivalent.

Nine submissions were received, of which three presented information and views on all aspects of the supply of crude oil and equivalent. The others dealt only with selected pools or specific regions of the province, or considered particular aspects, such as tertiary recovery or rising operating costs.

The hearing to consider the submissions was held in Calgary, 24, 25 and 26 June 1980, with N. Berkowitz, P.Eng. (Chairman), N. Strom, P.Eng. and G. A. Warne, P.Eng. (Acting Board Member), sitting. The following table identifies those who appeared at the hearing.

THOSE WHO APPEARED AT THE HEARING

Participants and Representatives (Abbreviations used in Report)	Witnesses
Canadian Petroleum Association (CPA) D. B. Macnamara	C. W. Dumett, P.Eng. B. Reilly, P.Eng. T. E. Randall, P.Eng. C. R. Mattinson P. A. Baker, P.Eng. G. Grant H. S. Simpson, P.Eng.
Chevron Standard Limited (Chevron) D. P. Lougheed	J. D. Giegerich, P.Eng.

THOSE WHO APPEARED AT THE HEARING

Participants and Representatives (Abbreviations used in Report)	Witnesses
Dome Petroleum Limited (Dome) C. E. Crawford	A. F. Balasch, P.Eng. D. N. Blades, P.Eng. C. D. Holder, P.Eng. A. P. Cachero, P.Eng. P. M. Sigmund, P.Eng. W. H. Elliott Jr., P.Eng. D. J. Rae, P.Geol. J. S. MacDonald, P.Geol. P. A. Achem, P.Geol. G. Chin, P.Geol. G. F. Perry, P.Eng. W. E. Richards S. J. Lane, P.Eng.
Esso Resources Canada Limited (Esso) J. E. Lowman	G. L. Haight, P.Eng. A. S. Broun, P.Geol. J. D. McFarland, P.Eng.
Gulf Canada Resources Inc. (Gulf) A. P. Scott	R. Lang, P.Eng.
Home Oil Company Limited (Home) J. R. Sears, P.Eng.	J. R. Sears, P.Eng. P. E. Lee, P.Eng.
Husky (Husky) M. Swan, P.Eng.	M. Swan, P.Eng. L. J. Doig, P.Eng.
Independent Petroleum Association of Canada (IPAC) C. K. Yates	J. H. Geddes, P.Eng. J. E. Horler P. V. Malowany, P.Eng. M. S. Abougoush, P.Eng.
Petro-Canada Exploration Inc. (Petro-Canada) Wm. Bone	J. McNicholas S. B. Smith, P.Geol. F. J. Bagley, P.Eng. D. Cornelson, P.Eng.
*Shell Canada Resources Limited	
*TransCanada Pipelines E.W.H. Malabone	

THOSE WHO APPEARED AT THE HEARING

Participants and Representatives (Abbreviations used in Report)	Witnesses
Energy Resources Conservation Board staff (Board staff) J. A. Bray, P.Eng. N. G. Berndtsson, P.Eng. R. Funk	

*Companies that filed a submission for purposes of cross-examination (ie: no evidence or views submitted)

2.3 MAIN TOPICS CONSIDERED

The demands of crude oil refiners can be roughly subdivided into four basic liquid hydrocarbon feedstocks: light-medium crude, heavy crude, pentanes plus and synthetic crude.[1] In order to assess the supply of crude oil and equivalent from these sources, it is convenient to consider the ultimate remaining potential that may be recoverable by known and foreseeable techniques, and then to examine the trends in productive capacity for each that might result. These matters are considered in two major chapters entitled "ultimate potential" and "productive capacity".

Oil supplies from developed conventional sources are mostly predictable with reasonable confidence. In contrast, estimates of oil supplies from sources such as tertiary recovery or bitumen synthetic crude plants must always be qualified to reflect the complex technical and economic uncertainties that may affect their development.

A further chapter therefore considers some factors that may influence development of supply. These include infill drilling for conventional supply, infill drilling for tertiary recovery, cost trends for oil production and lead times from concept-to-production for non-conventional oil supplies.

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[1] An explanation of the terminology and definitions of terms used in this report appears in Appendix A-3.

3 ULTIMATE POTENTIAL

In this chapter the ultimate potential of four types of crude oil and equivalent - light-medium, heavy, pentanes plus and bitumen synthetic - are assessed. As well as establishing the ultimate potential, it is necessary, in forecasting productive capacity, to prescribe the patterns of annual reserves growth for discoveries/additions and tertiary sources of crude oil. Therefore, these patterns will only be generally or briefly discussed in this chapter. Detailed comparative tabulations appear in Chapter 4 (Tables 4-2, 4-4, 4-7 and 4-9) and will allow closer scrutiny of productive capacity.

Ultimate potential forecasts have regard for the geological prospects, foreseeable technology and anticipated economic conditions. For the most part the ultimate potential forecast must assume that the economic climate for the very long range - 40 to 50 years or more - is favourable, whereas annual reserves growth patterns and forecasts of annual productive capacity should reflect nearer term factors, including current industry capacity to develop prospective sources, government policies, technical and environmental constraints and forseeable economic outlook.

3.1 LIGHT-MEDIUM CRUDE OIL

3.1.1 Established Reserves - Light-Medium

Views of Participants

CPA and Esso submitted estimates, shown in Table 3-1 of initial oil in-place, initial established reserves and production to date (1 January 1980) from conventional light-medium crude oil for the province as a whole. Petro-Canada adopted the established reserves published by the Board in IL 80-6.[1] Each of the main participants at the hearing except CPA also provided reserve estimates for individual pools in which the participant is a major operator.

TABLE 3-1 LIGHT-MEDIUM ESTABLISHED RESERVES
millions of cubic metres

	CPA	Esso	Petro-Canada	ERCB[a]
Initial Oil In-Place	5438	5260	5258	5343
Initial Established Reserves[b]	1947	1790	1794	1803
Cumulative Production (79-12-31)	1082	1080	1083	1081
Remaining Established Reserves	865	710	711	722

a ERCB Report 80-18
b Primary and enhanced recovery reserves including those from water and solvent flooding

CPA, Esso and Home raised concerns respecting the economic feasibility of recovering the full amount of the forecast initial established reserves. These concerns related to the rapid escalation of water production costs as oil productivity declines. Esso supported its contention with data for the Judy Creek Beaverhill Lake A pool and the Redwater D-3 pool, and Home presented similar details for the Swan Hills Beaverhill Lake A and B pool.

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[1] Informational Letter IL 80-6 published by the Board prior to the hearing. This outlined the then current forecast of productive capacity from established crude oil reserves.

Views of the Board

In IL 80-6 the Board provided current estimates of established reserves which were substantially identical with those set out in the Board's most recent reserve report, ERCB 80-18.

Although the CPA total is about ten per cent higher than other estimates, absence of individual pool data prevented examination of the basis for the difference. The Board forecasts some 722 million m^3 of light-medium ultimate remaining established reserves for the province as shown in Table 3-1 and in Appendix A-4.

3.1.2 Discoveries/Additions - Light-Medium

The estimated oil in-place potentials for discoveries/additions of light-medium crude oil submitted by participants that reported for the entire province are summarized in Table 3-2.

TABLE 3-2 LIGHT-MEDIUM DISCOVERIES/ADDITIONS POTENTIAL
millions of cubic metres

	CPA	Esso	Petro-Canada	ERCB
Initial Oil In-Place	420	940	1056	1000
Discoveries/Addition Potential	152	320	284	300

Views of CPA

CPA forecast the light-medium oil in-place attributable to discoveries/additions to be some 420 million m^3, and estimated a recoverable potential of some 152 million m^3 from primary and waterflood depletion, reflecting a recovery efficiency of 36 per cent.

CPA assumed that a doubling of the number of exploratory wells from 30 000 to an ultimate 60 000 wells would result in discovery of a median average of 5300 m^3 of oil per exploratory well on a diminishing additions basis. Ninety-five per cent of the new discoveries were assumed to be light-medium crude and five per cent heavy crude, and it was anticipated that the momentum for exploratory drilling would be mainly sustained by a continued search for natural gas. CPA observed, however, that the temperature-depth limitation which affected preservation of oil over geological time, precluded significant oil discoveries in the more deeply buried sediments. CPA also believed that new discoveries would be made in a host of small pools rather than in large accumulations.

Views of Dome

Dome did not provide a forecast of the new discoveries potential for the entire province. However, in its submission to the deep basin pipeline hearing[1], Dome presented a wide-ranging analysis of proved and ultimate potential for light-medium crude oil from a 20 000 - 30 000 square mile area in northwestern Alberta. Dome referred to production from wells completed in the Halfway, Doig, Charlie Lake and Baldonnel formations of the Triassic, and from the Dunvegan and Cardium formations. It emphasized the Dunvegan sands to which it attributed a potential of 80 million m^3 oil in-place per township over 15 townships. Dome noted that where Dunvegan sands contain 7.6 m or more of net pay with average permeabilities of 0.5 millidarcies or more, 50 per cent of the wells can be stimulated to produce 1.6 m^3 per day. Dome did not specify a primary and waterflood ultimate potential for the Dunvegan as it attributed the bulk of the future potential to tertiary recovery.

Dome similarly drew attention to the prospective potential of the lower Cardium main sand, noting that it is 10 to 30 m thick in the Kakwa-Obed area, and could occur over some 100 townships. Dome noted that the lower Cardium main sand generally has low porosity (8 per cent) and low permeability (0.5 millidarcies), but that oil can be recovered from such sands after fracturing. Dome did not discuss or propose a primary or waterflood potential for the lower Cardium as it attributed the main potential to tertiary recovery.

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[1] Application No. 800113 to the ERCB.

In answer to questions, Dome contended that the deep basin area is "quite certain" to yield reserves of 38.3 million m^3 by conventional recovery methods.

Views of Esso

Esso forecast 940 million m^3 of light-medium oil in-place from discoveries and extensions, and considered 320 m^3 recoverable by conventional methods.

Esso forecast light-medium new discovery potential by subdividing the basin into stratigraphic-geographic units. In Esso's judgement, the average size of pools discovered in the future will generally be smaller than those discovered in the past. A Monte Carlo simulation of the probability of the potential recoverable oil for each geologic unit resulted in a mean value of 317 million m^3 of future potential from new discoveries, of which 45 per cent would be from Cretaceous sediments and 40 per cent from Devonian sediments.

Esso noted that its latest forecast of new discovery potential is more optimistic than the estimate contained in its 1978 submission to the NEB. It credits this to recent encouraging exploration results in the Cretaceous and Devonian units, and to real price increases that make previously marginal reserves economic. Although it acknowledged that the possibility of new geologic plays, such as the Pembina Nisku basin, as well as further improvements in technology or economic conditions could render its current mean value estimate conservative, it believed its upper probability limit of 450 million m^3 would cover these possibilities. Having regard for the current level of exploration activity, Esso expected that three-quarters of its projected 320 million m^3 of discoveries/additions would be found by the year 2000.

Views of Petro-Canada

Petro-Canada estimated light-medium oil in-place from discoveries and extensions at some 1056 million m^3 by considering the geographical distribution of all geological horizons in the province. The estimates had regard for frequency and size of pool occurrence and extent of formation and deposition trends. New discoveries are anticipated in the horizons that contain presently established reserves. Some 270 million m^3 oil in-place are anticipated in the Devonian, with a recovery of some 120 million m^3, but the most important contributor would be the Cretaceous. It estimated some 477 million m^3 oil in-place from the "deep basin" in northwestern Alberta, using a volume of sediments approach and extrapolating experience from the Ferrier-Bearberry region of south-central Alberta. The recoverable reserve potential was estimated at 284 million m^3, of which 95 million m^3 would be derived from deep basin sediments. Recovery factors were based on historical averages for each major geological horizon.

The light-medium crude oil potential for new discoveries was assumed to develop on a growth pattern of some 20.7 million m^3 annually until about 1986 after which the development rate would decline.

Views of Other Participants

Other participants did not express opinions on ultimate potential from new discoveries. However, several expressed concern over the netback to operator from product prices and the possibility of declining incentive to explore for and develop new reserves.

Views of the Board

The Board concurs with participants that, with much of the Alberta basin area explored and developed,

- estimates of geologic probability of new discoveries are likely to prove fairly reliable,
- the prospects for large individual discoveries are minimal, and
- future discoveries will be comparatively small, will usually accrue from exploration for gas, and will tend to be added at a rate commensurate with the pace of drilling activity.

Whereas the Board agrees with much of the evidence submitted, there are some specific aspects on which the Board's views diverge somewhat from those of the participants. Esso's expectation that 40 per cent of the new discoveries, roughly equivalent to 130 million m^3 recoverable reserve, will be found in the Devonian appears optimistic. In the Board's view, that potential is about 100 million m^3. The Board also notes that whereas all participants agree that the Cretaceous is likely to be the other major contributor of the new discovery reserves, their estimates of the potential varied widely. The Board believes that the aggregate contribution from Cretaceous sediments, including that from the partly explored areas of southern and central Alberta and from the relatively less explored geo-syncline belt which extends from the foothills disturbed areas into the so-called "deep basin" area, could total upwards of 150 million m^3 of new light-medium reserves recoverable by conventional recovery mechanisms.

While concurring with CPA that major-sized pool discoveries are unlikely and that temperature-depth limitations preclude significant oil discoveries in deep sediments of the Alberta basin, the Board considers CPA's overall forecast of ultimate potential to be conservative.

The Board believes that contributions from lesser geological horizons and some further appreciation of established reserves, when combined with additions in the Devonian and Cretaceous sediments, will provide not less than 300 million m^3 of new reserves. The Board expects these to be added more or less in direct relation to the pace of drilling, and agrees with Esso that three-quarters of the total will probably be found and booked in the next 20 years.

3.1.3 Tertiary - Light-Medium

Extensive laboratory investigations have been carried out over the past three decades with a view to developing new methods for recovering oil remaining in a reservoir after conventional water or gas displacement. These tertiary methods usually involve complex fluids mixing and displacement regimes for recovering immobile by-passed oil.

A developer must have confidence that a method is technically viable and will yield a worthwhile return before applying it to a reservoir. In addition, because of the lag in production response and the significant front end investments, there must be confidence in the economic outlook before such a program is undertaken.

CPA, Esso and IPAC presented estimates of light-medium tertiary potential of the entire province while Dome, Home, Gulf and Chevron confined their assessments to particular parts of the province or particular pools. Petro-Canada provided a combined forecast of the development of light-medium and heavy crude oil productive capacity from tertiary processes, but did not give details on the related ultimate potential. It considered this aspect to be adequately dealt with in studies by D&S Petroleum Consultants for IPAC.

Table 3-3 presents the estimates of light-medium tertiary potential by the participants and the Board.

TABLE 3-3 LIGHT-MEDIUM TERTIARY POTENTIAL
millions of cubic metres

	CPA	Esso	IPAC	Dome	ERCB
Tertiary Potential	310	430	433[a]	237[b]	300
Incremental Recovery Factor[c]	0.093	-	0.135	0.20	0.10

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a 150 $/m^3 netback case
b Pembina Cardium Pool only
c Using resource base oil in-place

Views of CPA

CPA evaluated the light-medium tertiary potential for 23 comparatively large pools which represent 40 per cent of Alberta's enhanced recovery resource base. It omitted any pools with thin oil columns, with recovery mechanisms which will recover over 65 per cent of the oil in-place or with less than 10 million m^3 of remaining oil in-place. CPA concluded that hydrocarbon miscible and carbon dioxide (CO_2) miscible recovery methods were most promising and could yield 290 million m^3 of additional recoverable reserves from pools with established reserves and 20 million m^3 from pools expected to be discovered. These estimates included reserves from projects which have been approved by the Board but not yet commenced. The overall effect would be to increase the average recovery factor from the light-medium resource base by 9.3 percentile. Additional wells were assumed to be drilled where necessary for injectors or to increase productivity where desirable.

Views of Chevron

Chevron did not present estimates of tertiary recovery potential, but stated that an affiliated company, Chevron Oil Field Research Company, (at La Habra, California) is actively engaged in fundamental research and field testing of sophisticated enhanced recovery processes. Although it has no firm plans for applying such processes to oil pools in Canada, several pools in Alberta are being reviewed.

Views of Dome

Dome presented the results of tertiary recovery studies and tests it and others had made in the Pembina Cardium pool. From these it estimated that the tertiary recovery potential for that pool alone could be as high as 237 million m^3. Dome postulated that a miscible flood of the deep basin Dunvegan sands, developed on 16-hectare or possibly 32-hectare spacing, could generate an ultimate potential of some 175 million m^3 of oil. The application of miscible flooding on similar well spacing in 30 townships in the Lower Cardium could yield a potential of 560 million m^3. Dome proposed an ultimate deep basin potential of some 890 million m^3 from all horizons and from all methods, but placed heavy reliance on tertiary methods.

Dome also stressed the need for favourable economic policies, including application of the province's current royalty relief incentives to enhanced recovery and eligibility for world crude oil prices, in order to achieve the large tertiary potential.

Views of Esso

Esso considered miscible flooding with LPG or carbon dioxide to be the most promising tertiary methods. It based its analysis on a review of prototype pools selected for each major producing zone. A tertiary method which appeared suited to the particular zone on the basis of the zone's reservoir characteristics was selected, and economic incentives for tertiary recovery were then evaluated for a range of crude oil prices under current tax and royalty provisions, with and without application of royalty rebate provisions now available to Alberta tertiary projects. The lowest crude price which would yield a 10 per cent discounted cash flow rate of return in constant 1980 dollars was then determined, and the recovery indicated by the prototype was scaled up to give the reserves expected for the zone. In this manner Esso estimated light-medium tertiary potential approximately as follows:

Price ($/m^3)	Tertiary Potential	
	With Royalty Rebate million m^3	Without Royalty Rebate million m^3
100	170	60
150	380	145
200	420	250
300	430	350

Of the total potential of 430 million m^3, 360 million m^3 would be obtained from established reserves while some 70 million m^3 would be obtained from new discoveries. It stated that at world prices and present royalty and tax rates, only 85 per cent of the miscible and none of the surfactant project reserves would be exploitable without the enhanced recovery royalty rebate.

Esso estimated that at the current domestic price of 95 $/m^3 and with current revenue sharing, one-third of the technical tertiary potential could be developed to yield a 10 per cent constant dollar rate of return. However, at the current world price of 220 $/m^3, essentially all of the technically feasible tertiary potential could be developed to yield a 10 per cent constant dollar rate of return. It added that at the domestic price of 95 $/m^3, in effect at June 1980, only a third of these potential reserves could be produced without the Alberta royalty rebate now available.

Esso added that the pace at which tertiary projects will be undertaken depends on perceived technical and financial risks. It observed that the technical risks are reduced by successful pilot projects or the success of similar commercial schemes. If economic risks are reduced, greater technical risks can be taken and tertiary projects can be developed more rapidly.

Views of Gulf

Gulf did not comment on the tertiary recovery potential of the province as a whole, but indicated that it was proceeding with plans to initiate hydrocarbon miscible flood projects in the Stettler D-2A pool and in a part of Fenn Big Valley D-2A pool in 1982, and in the Goose River Beaverhill Lake A pool in 1987. It also foresaw the possibility of a CO_2 miscible project in the Snipe Lake Beaverhill Lake pool in 1985. If successful, these projects would result in incremental reserves totalling 11.5 million m^3.

Views of Home

Home confined its comments respecting tertiary recovery potential to the Swan Hills Beaverhill Lake A and B pool which is an important candidate for a tertiary project. It stated that subject to a supply of suitable miscible fluids and adequate economic incentives, a miscible flood project could be initiated in the pool in 1983. Response would be observed beginning in 1985 and incremental reserves equivalent to 20 per cent of the original oil in-place would be recovered over the life of the pool. Detailed studies to improve the assessment of prospective tertiary recovery methods are presently in progress.

Home emphasized the need for economic incentives and illustrated this with production rates and operating costs for the period 1977 to 1979 which were projected to 1985. The data showed producer netbacks increased by only 6.7 per cent per year over the period 1 January 1977 to July 1980, while inflation, based on the Gross National Product inflation index increased at an average of 7.8 per cent per year. Home stated that on the basis of preliminary detailed studies and increments in crude oil prices of 12 $\$/m^3$ per year with the present royalty and fiscal regimes, tertiary recovery projects would be uneconomic. However, it indicated that, using a modified royalty schedule, a carbon dioxide miscible project would be viable. A hydrocarbon miscible project also would be economic if the royalty on miscible hydrocarbon fluids used in the project were removed.

Views of IPAC

IPAC submitted a study of the potential for enhanced recovery in Alberta performed for it by D&S Resources Engineering Ltd. The study of light-medium pools excluded from consideration pools still under primary depletion, pools already undergoing miscible displacement, and pools with less than one million m^3 of reserves presently being waterflooded.

The screening process resulted in a total of 74 pools, representing 3200 million m^3 of initial light-medium oil in-place, being evaluated. The relatively lighter density crude oil pools of southeastern Alberta, from which oil is marketed as heavy crude oil, were included in IPAC's light-medium oil in-place. In order to simplify predictions, the analysis utilized one mechanism for each process considered, with CO_2 being used for miscible, micellar for chemical and wet combustion for thermal processes. Results of economic analyses were expressed in 1980 constant dollars, with the cash flows at various producer netback levels being discounted at 7 per cent.

Five producer netbacks were investigated, with the following results:

Netback $/m^3	50	75	100	150	No Limit
Light-Medium Tertiary Potential Millions m^3	16	253	285	433	610
Capital - $Million	60	2 000	3 000	7 000	13 000
Unit Capital - $/m^3	4	11	11	15	21
Operating - $Million	500	12 000	13 000	24 000	48 000
Unit Operating - $/m^3	32	45	47	56	79
Total Cost - $Million	560	15 000	16 000	31 000	61 000
Unit Cost - $/m^3	36	56	58	71	100

The results also show that if decisions were taken in 1980 to launch the prospective tertiary recovery schemes, major capital investments and field construction activities would get underway in 1983. Initial production response would be experienced as early as 1985, (ie. two years after commencement of operations) would then gradually climb, and would reach a peak approximately ten years after initial response. The overall period of tertiary operations would be approximately 30 years.

Because tertiary recovery is very capital and operating costs intensive, IPAC concluded that a producer netback of only 50 $/m^3 would make virtually all of the pools uneconomic for conversion to tertiary recovery. It also stressed that up to ten years are required from the start of tertiary recovery projects to achievement of full commercial production. If significant tertiary potential is to be realized in the next 10 to 20 years, early firm commitments by governments are therefore necessary to ensure adequate producer netbacks and an early response by industry to launch tertiary schemes would have to follow. IPAC contended that results of its study showed that a substantial tertiary potential exists in existing light-medium pools. Most of the potential is in the Keg River, Gilwood and Beaverhill Lake pools, as shown in the following table:

Geological Horizon	Incremental Tertiary Recovery for 150 \$/m^3 netback millions m^3
Keg River/Gilwood	89.9
Beaverhill Lake	261.3
Leduc & Nisku	35.4
Mississippian	12.8
Triassic/Jurassic	5.5
Mannville	12.4
Viking	5.6
Cardium	10.4
	433.3

Views of Petro-Canada

Petro-Canada expressed confidence that tertiary recovery methods could yield substantial additions to crude oil reserves but noted that, under the present pricing and fiscal regimes, such projects are rarely economically justified. It stated that, given the technical and economic problems to be overcome, tertiary recovery schemes are unlikely to make a significant contribution to production in the 1980s.

Petro-Canada described programs for miscible flooding of three Nisku pools in the Brazeau Field that could yield 4.1 million m^3 of incremental reserves. It determined that the royalty relief provisions of Section 4.2 of the Petroleum Royalty Regulations would transform these tertiary projects from uneconomic status to providing an incremental rate of return of 17 per cent relative to a base-case of waterflooding.

Petro-Canada advised that it has a research program for developing sophisticated enhanced recovery technology, and it expected that this will significantly improve the reliability and economic feasibility of enhanced recovery projects.

Views of the Board

The Board agrees that a large light-medium tertiary crude oil potential exists in the province, since 70 per cent of the oil will remain unrecovered after primary and conventional enhanced recovery operations. It also agrees that tertiary recovery projects

- involve relatively complex recovery mechanisms
- require extensive analysis and field testing to establish their applicability to particular reservoirs
- demand large capital investment
- involve lengthy lead time for design, equipment procurement and installation of supporting facilities
- must usually be operated for a considerable period before production response is achieved
- yield a modest response in productivity which usually extends over a period of 20 to 30 years
- should be assessed on the assumption of world prices and existing royalty and tax provisions.

The estimates of tertiary potential submitted by Dome for the deep basin Cardium and Dunvegan sands have to be considered speculative because only a few successful producing wells have been completed in the area and these wells have comparatively low productivity. Though the application of CO_2 tertiary to some parts of the Pembina Cardium pool may be feasible, the Board considers the Dome estimate for the pool to be more an assessment of economic sensitivity that a measure of actual potential. The Board notes that IPAC's studies attributed only 10 million m^3 of its total 433 million m^3 tertiary potential to the Cardium horizon compared to Dome's 237 million m^3 for the Pembina Cardium alone.

On the basis of its review of tertiary projects in the United States and of engineering studies of pools candidate for such projects in Alberta, the Board does not expect as favourable a potential as estimated by IPAC or Esso.

The Board believes that a long-range tertiary recovery potential of some 300 million m^3 is feasible, provided adequate economic incentives are available. This estimate is close to that of CPA and assumes the allocation of world prices to tertiary production, current tax and royalty levels, and special incentives such as the royalty rebate provisions of the Alberta Petroleum Royalty Regulations. The Board concurs with IPAC that the main sources of light-medium tertiary oil are in the Upper and Middle Devonian oil reservoirs.

3.2 HEAVY CRUDE OIL

3.2.1 Established Reserves - Heavy

Views of the Participants

CPA and Esso submitted forecasts of initial oil in-place, initial established reserves and production to date (1 January 1980) of conventional heavy crude oil, as shown in Table 3-4. Petro-Canada adopted the reserves published by the ERCB.

TABLE 3-4 HEAVY ESTABLISHED RESERVES
millions of cubic metres

	CPA	Esso	Petro-Canada	ERCB[a]
Initial Oil In-Place	695	710	765	780
Initial Established Reserves	90	100	90	87
Cumulative Production	47	50	47	49
Remaining Established Reserves	43	50	43	38

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[a] ERCB Report 80-18

Husky provided estimates for five pools which it operates in Lloydminster.

Views of the Board

The Board finds that there are only modest differences in the submissions and adopts the values in column 4 of Table 3-4 as acceptable estimates of established reserves of heavy oil. The Board's current estimates for individual pools are outlined in Appendix A-4.

3.2.2 Discoveries/Additions - Heavy

The estimates of province-wide oil in-place and established reserves potential from new discoveries of heavy crude oil are summarized and compared in Table 3-5. Dome's estimates for southeastern Alberta and Lloydminster are also included in the table.

TABLE 3-5 HEAVY DISCOVERIES/ADDITIONS POTENTIAL
millions of cubic metres

	CPA	Esso	Petro-Canada	Dome		ERCB
				SE Alta	Lloydminster	
Initial Oil In-Place	360	260	1195	378	795	500
Discoveries/ Additions Potential	40	30	95	72	76[a]	40

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[a] 115 $\$/m^3$ netback

Views of CPA

The CPA estimated oil in-place attributable to new discoveries, including nominal extensions and additions to existing heavy crude reservoirs, to be some 360 million m^3 heavy crude. It saw a potential of some 40 million m^3 heavy crude recoverable from primary and waterflood depletion, representing 11 per cent recovery.

Views of Dome

Dome did not present a forecast of the discoveries/additions potential for the entire province, but discussed the potential of three specific regions. These included the heavy crude areas of southeastern Alberta and Lloydminster for which the discoveries/additions potentials are shown in Table 3-5.

Dome forecast discoveries/additions of 378 million m^3 heavy crude oil in-place, in an area of 480 townships in southeastern Alberta with a primary and waterflood recovery of 72 million m^3. Dome justified the 19 per cent recovery factor by reference to ERCB pool data. It noted the 325 million m^3 of initial established oil in-place at year-end 1978, with recoverable reserves of 52.7 million m^3, indicated an average recovery factor of 16 per cent.

Dome noted that the drilling density in southeastern Alberta is low and therefore forecast reserves growth by projecting the growth experienced in the 1970s over the 20-year forecast period. It emphasized that optimization of production methods, including better well completions, could make an important contribution to higher recovery.

Dome also identified a study area in Alberta, some 42 by 120 miles approximately centred on Lloydminster and abutting the Saskatchewan border. For this area, Dome determined some 460 million m^3 of heavy oil in-place, as summed from the Board's 1978 reserves report, and further identified an estimated new discovery potential of 635 million m^3 of heavy oil in-place in the northwest part of the study area. Another 160 million m^3 of heavy oil in-place was expected to be found within the study area during the 20-year forecast period. Dome thus forecast an ultimate potential of some 1300 million m^3 of heavy oil in-place for the study area. Dome added that it is participating in developing the northwestern quadrant of the study area, and estimated that 60 per cent of some 120 sections would have sands of 10 m or greater thickness.

Dome reported that it drilled 45 Lloydminster area wells in 1978, 70 in 1979, and, to date, 40 of the 260 wells projected for 1980. The wells were divided about equally between Saskatchewan and Alberta.

Dome presented the results of an analysis of the Lloydminster heavy crude area that related the potential reserves to netback to the producer. The results for primary recovery were as follows:

Netback 1980 $\$/m^3$	Discoveries/ Additions Potential million m^3	Minimum Initial Well Productivity Accepted in the Study $m^3/d/well$
227	87	0.8
115	76	1.6
82	48	2.4
64	15	3.2

Dome's analysis showed most of the potential recovery could be obtained at a netback of 115 $\$/m^3$.

Dome's cost information in 1980 dollars was as follows:

• Drilling primary wells	170 000 $/well
• Primary operating costs	1500 to 2500 $/month/well
• Tertiary capital costs	15 to 18.5 million $/section
• Tertiary operating costs	36 to 42 $\$/m^3$

Views of Esso

Esso estimated some 260 million m^3 heavy crude oil in-place from discoveries/additions, and expected recovery of some 30 million m^3 by primary and waterflood schemes. The corresponding recovery efficiency is 11.5 per cent.

Esso provided a brief summary of its 1978 study of the reserves potential in the Lloydminster area, and observed that heavy crude activity has been slower than anticipated. Accordingly, its forecast of ultimate potential was lower than in 1978. It expected discovery of some 820 million m^3 of oil in-place, but that only some 110 million m^3, having a 12° or greater API gravity and not underlain by water, would contribute recoverable reserves. Esso attributed an oil in-place of 150 million m^3 to southeastern Alberta.

Views of Husky

Husky stated that the potential for new discoveries in the Lloydminster area is insignificant when compared with the potential associated with tertiary recovery methods. It estimated 1.5 and 13.7 million m^3 would be produced in the 20-year period by conventional and tertiary methods respectively from additions to five major pools it considered in the Lloydminster - Wainwright area.

Views of Petro-Canada

Petro-Canada estimated that heavy oil in-place from new discoveries/ additions would be some 1195 million m^3. Average recovery factors were developed for each major geologic horizon, and these were then applied, to the corresponding oil in-place to obtain a heavy crude potential, including that from waterflood, of 95.6 million m^3. Recoverable reserves of 57 million m^3, or some 60 per cent of heavy crude discoveries/additions were expected to come from pool extensions and additions. The annual growth of conventional heavy crude reserves was forecast to continue at a constant 4.77 million m^3 over the 20-year forecast period.

Petro-Canada viewed the heavy crude oil potential of eastern Alberta favourably, and expected to develop additional heavy crude oil pools of the Kinsella-Wainwright quality.

Views of the Board

The Board notes that the participants estimates of heavy crude oil in-place discoveries/additions ultimate potential differ considerably. The Esso and CPA estimates are in the 300 million m^3 range while Petro-Canada and Dome estimated about 1200 million m^3. Estimates of recoverable heavy oil potential differ by commensurate degree with Esso and CPA in the 30 to 40 million m^3 range contrasted with Petro-Canada and Dome in the 100 to 150 million m^3 range. Based on reviews of the geological information by its staff, the Board discounts the Petro-Canada and Dome expectations of future oil in-place discoveries. Also, although the Dome economic analysis is considered reasonable in terms of netback and initial well productivity, the Board does not agree with the recovery potentials estimated because it has doubts about the extent of the resource base. The Board believes more direct field evidence is required to substantiate the existence of the very large heavy crude resource base attributed to Lloydminster in order for it to be recognized as potential. Having regard for the Husky, CPA and Esso submissions and for Board staff studies, the Board considers it more reasonable to set additional heavy crude oil in-place potential at some 500 million m^3, and, an estimated recovery factor of 8 per cent, to forecast an ultimate potential of 40 million m^3 recoverable. The Board would expect most of this potential to be developed in the 20-year forecast period.

3.2.3 Tertiary - Heavy

The principal tertiary recovery methods considered for heavy crude oil were thermal and chemical. Thermal methods are mainly steam injection and in situ combustion, while chemical methods comprised waterflooding with alkali surfactants or polymer additives.

CPA, Esso and IPAC presented estimates of heavy crude tertiary potential for the entire province, as shown in Table 3-6, while Dome and Husky confined their assessments to parts of the province and particular pools. Petro-Canada considered tertiary heavy crude oil to have appreciable potential, but did not provide any details

TABLE 3-6 HEAVY TERTIARY POTENTIAL
millions of cubic metres

	CPA	Esso	IPAC	Dome		Husky	ERCB
				SE Alta	Lloydminster	7 Schemes	
Oil In-Place	695[a]	970[b]	685[a]	-	1300	-	300
Tertiary Potential	170	30	89[c]	13	142[d]	21	75

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a Established reserve base only
b Sum of oil in-place from Tables 3-4 and 3-5
c See separate table under Views of IPAC
d 115 \$/m^3 netback

Views of CPA

CPA estimated the potential for tertiary recovery in heavy crude oil pools by assessing the effectiveness of tertiary methods for 11 pools holding 38 per cent of the heavy enhanced recovery resource base. A favourable economic climate was assumed. It concluded that chemical methods and steam or fire flooding were the most promising techniques and could yield 120 million m^3 and 50 million m^3 of additional reserves respectively, from established reserves and new discoveries. It estimated that 4030 infill wells would be required, mainly for injection.

Views of Dome

Dome analysed the tertiary recovery potential of southeastern Alberta using screening criteria from a study by the Petroleum Recovery Institute. The analysis assumed no technical risk. The criterion for economic feasibility of a project was an eight per cent rate of return (in 1980 dollars). Provision was made for lead time, such as for pilot tests. Assuming in situ combustion, CO_2 miscible flooding and polymer flooding methods, Dome estimated a tertiary potential of 13 million m^3 from an oil in-place of 87 million m^3 in a group of existing pools in southeastern Alberta[1].

Dome extended its analysis of the Lloydminster heavy crude area to relate tertiary potential to netback. Assuming application of in situ combustion and steam injection methods, the following were the results:

Netback 1980 $\$/m^3$	Primary and Tertiary Potential million m^3	Incremental Tertiary Potential million m^3	Minimum Initial Well Productivity Accepted in the Study m^3/d/well
227	230	143[a]	0.8
115	218	142	1.6
82	160	112	2.4

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[a] Dome did not present the results in incremental terms. These were obtained by difference with Dome's primary recovery analysis.

Virtually all of the tertiary potential would be obtained at a netback of 115 $\$/m^3$.

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[1] Many of the pools in Dome's analysis are the lower density crude oil pools (medium crude oil) that are classed as heavy crude oil for market purposes.

Views of Esso

Esso estimated the tertiary recovery potential for heavy crude oil in the same manner as it estimated the potential for light-medium crude oil pools. The principal recovery methods were assumed to be wet combustion and surfactant flooding. It eliminated many pools as having little or no potential because of thin pay thickness and/or bottom water. On this basis it estimated the heavy tertiary potential from established reserves and discoveries/additions to be 30 million m^3.

Views of Husky

Husky confined its submission to the potential of the Lloydminster-Wainwright heavy crude oil areas, and based its comments primarily on detailed knowledge of major pools in which it is a principal interest owner.

Husky stated that although tertiary recovery projects have potential for significantly increasing recoverable reserves, such projects are expensive and require substantially higher oil prices or lower royalties. In its assessment of project feasibility, Husky assumed that the production would have unrestricted access to markets. It stated that while it had previously considered development of up-grading facilities, it now concluded that capability for producing the oil must be established before up-grading plants could be seriously pursued.

Husky identified plans for initiating fireflood projects in the Sparky zone at Lloydminster in 1982, 1983, 1985 and 1990. In addition, a chemical flood process is to be initiated in the Wainwright pool in 1990, and fireflood and steamflood projects in the Wildmere Lloydminster A pool are planned to commence in 1985 and 1988 respectively. Each project would begin with a pilot scheme which, subject to satisfactory performance, would then be expanded to a commercial project. Husky estimated an ultimate potential of 21 million m^3 for these seven schemes.

Views of IPAC

The IPAC study of tertiary recovery from heavy crude oil pools was performed by D&S Resources Engineering Ltd. on a similar basis to that for light-medium crude oil. The study excluded from consideration pools with less than one million m^3 of oil in-place and pools not on production. It also excluded 14 pools in southeastern Alberta, which the ERCB had classified as "heavy" for market purposes and which were included in IPAC's light-medium tertiary study described previously (see Section 3.1.3). Following a screening process, 11 pools, all in the Cretaceous horizon, with 685 million m^3 of oil in-place (39 per cent of the oil in-place for the established heavy crude oil reserves) were selected for review. For simplicity all analyses were based on the wet combustion process. In each case a 5-spot configuration with each pattern comprising 10 hectares was assumed. Project areas within a pool were assumed to be added at a maximum rate of 500 hectares per year. Capital and operating data were obtained from pool operators, other D&S studies, and from a report by the Canadian Energy Research Institute.[1]

The procedure of determining netback to the producer described earlier for light-medium crude oil was used, with four levels of netback being investigated.

The pools examined were scheduled for conversion to tertiary projects during the period 1984 to 1986. The following results were obtained:

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[1] Enhanced Oil Recovery Potential in Canada by J. Philip Prince, Canadian Energy Research Institute, March 1980.

Netback 1980 $/m^3	50	75	100	150
Heavy Recoverable Reserves Millions m^3	18	37	69	89
Capital - $Million	170	370	720	1 500
Unit Capital-$/m^3	9	10	11	17
Operating - $Million	530	1 200	2 700	4 300
Unit Operating-$/m^3	29	33	39	49
Total Cost - $Million	700	1 570	3 420	5 800
Unit Cost - $/m^3	38	43	50	66

The incremental tertiary potential predicted at the 150 $/m^3 netback level amounts to 34 per cent of the original oil in-place compared with an average of 10 per cent by present recovery methods. It was concluded that pools not reviewed in the study may also have tertiary recovery potential but could not be economically exploited with current economic incentives.

Although only the wet combustion process was used in the analysis, other thermal processes, such as steam flooding, could be used in some pools. Chemical and miscible flood processes were considered inapplicable because of the relatively high crude oil viscosities.

Views of Petro-Canada

With respect to heavy crude oil, Petro-Canada noted that it is evaluating prospects for caustic flooding in the Wainwright field and plans to begin a second pilot project using this method in early 1981. If successful, a field-wide scheme would be implemented by 1985. Preliminary analysis indicates such a project could yield incremental reserves amounting to 5 to 10 per cent of the original oil in-place. If succesful in Wainwright, it would also be considered for Viking-Kinsella.

Petro-Canada is currently operating a thermal pilot project in the Viking-Kinsella Wainwright D pool. It consists of steam flood and fireflood patterns and, on the basis of preliminary evaluation, could yield an incremental recovery of 10 to 20 per cent of the original oil in-place. If successful at Viking-Kinsella, the process would also be considered for the Wainwright field.

Views of the Board

While thermal recovery techniques have been successfully used to recover heavy conventional crude oil from some pools in the United States and Saskatchewan, only pilot and experimental tests have been conducted in Alberta, and most of these related to bitumen deposits. Nonetheless, as noted by several participants at the hearing, the work performed thus far indicates considerable promise for thermal recovery methods in heavy crude oil pools. The Board also concurs with the view, emphasized in the submissions, that technical refinements and greater economic incentives are needed to produce a significant portion of the heavy oil tertiary potential.

Chemical methods, usually entailing injection of water containing alkaline or surfactant materials, also have been extensively tested with mixed success in the United States, but have not been tested to any significant extent in Alberta. CPA, Esso and Petro-Canada indicated some potential for alkaline (caustic) flooding methods for the lower density, less viscous heavy crude oils. Generally these methods do not yield as large a recovery improvement as thermal methods, but in particular situations, such as a sequel to waterflooding, they may be more effective than thermal methods. The high cost of chemicals and the need to develop a more detailed knowledge of the characteristics of the particular pool than is required for other recovery methods has impeded development. The Board agrees that such methods have some potential, but considerable testing is necessary to demonstrate their applicability to particular pools.

The CPA and IPAC submissions addressed the tertiary potential of established reserves while Esso presented views on both established and discovery/addition reserves. All participants expressed considerable doubt that much of the tertiary potential could be realized without substantially higher netbacks to the producer. In assessing the potential the Board, like the participants, assumed higher prices or other incentives would be introduced to improve the economics of such projects.

As discussed above and indicated in Table 3-6, estimates of the heavy oil tertiary potential vary widely. The Board also notes that there were some differences in how participants defined heavy crude oil. After deleting medium density crude oil pools in southeastern Alberta, which are nominally classed as heavy for marketing purposes, the Board's estimate of potential oil in-place is 1200 million m^3, composed of 700 million m^3 established and 500 million m^3 discoveries/additions. The Board agrees that pool size, formation thickness and underlying water, as noted by IPAC and Esso, will considerably reduce the potential for thermal and chemical tertiary recovery methods. For purposes of this report the Board has assumed that one-quarter of the total potential, 300 million m^3 of heavy crude oil in-place, would be in pools of sufficiently high quality to render them amenable to tertiary recovery.

The Board has also assumed that the weighted average tertiary recovery factor would be 25 per cent, and thus allow production of 75 million m^3. But it emphasizes that this estimate is very hypothetical in view of the lack of field performance data.

3.3 PENTANES PLUS ESTABLISHED RESERVES AND DISCOVERIES/ADDITIONS

Views of Participants

Only CPA, Dome, and Petro-Canada made submissions with respect to the ultimate potential for pentanes plus. Their estimates are shown in Table 3-7.

CPA estimated the pentanes plus/gas ratio of new discoveries on a judgement basis; Dome based its estimate on a detailed area/zone study by a consultant; and Petro-Canada used the historical ratio. Petro-Canada indicated that the historical ratio may be high in light of recent trends but that the estimate should not be revised at this time, due to uncertainties in estimates of the ultimate potential for gas and lack of detailed analysis of recent trends.

Views of the Board

As shown in ERCB Report 80-18[1], the Board estimated the initial established reserves of pentanes plus at 31 December 1979 to be 244 million m^3. Its corresponding estimate of initial established reserves of marketable gas on a 37.4×10^6 joules/m^3 basis is 2.66 trillion m^3. The Board's current estimate of the ultimate potential for gas, as discussed in ERCB Report 79-G[2], is in the range of 3.7 - 3.9 trillion m^3. For purposes of this report, the Board has adopted the mid-range value of 3.8 trillion m^3, and its estimate of gas yet to be discovered is thus some 1.14 trillion m^3.

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[1] Alberta's Reserves of Crude Oil, Gas, Natural Gas Liquids, and Sulphur, at 31 December 1979, ERCB 80-18.

[2] Ultimate Potential for Gas in Alberta. ERCB Report 79-G, November 1979.

The Board now believes that application of the historical pentanes plus/gas ratio to new gas discoveries, as was done in ERCB Report 80-18, may lead to an optimistic estimate of the ultimate potential, since much of the remaining gas potential lies in younger sediments which tend to have less natural gas liquids. The lower pentanes plus/gas ratio adopted in this report reflects this view.

On the basis of its own studies and the evidence presented by the participants, the Board estimates that the average pentanes plus/gas ratio of gas discovered in the future will be some 65 m^3 per million m^3. Applying this ratio to the Board's estimate of gas discovered yields some 74 million m^3 of pentanes plus yet to be discovered.

The ultimate potential, comprising pentanes plus from established reserves and discoveries/additions, is estimated as 318 million m^3.

The estimates submitted at the hearing and those of the Board are shown in Table 3-7.

TABLE 3-7 PENTANES PLUS ULTIMATE POTENTIAL

	Initial Established Reserves @79-12-31	Pentanes Plus		Ultimate Potential for Gas	Pentanes Plus/ Gas Ratio for New Discoveries
		Discoveries/ Additions	Ultimate Potential		
	million m^3	million m^3	million m^3	trillion m^3	m^3/million m^3
CPA[a]	178.0	57.0	235.0	4.25	30.0
DOME	240.0	92.0	332.0	3.86	66.5
PETRO-CANADA	239.8	145.2	385.0	3.91	98.8
ERCB	244	74	318	3.8	65
CUMULATIVE PRODUCTION	119	-	119		
REMAINING	125	74	199		

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[a] Does not include volumes recoverable from mainline reprocessing plants

3.4 BITUMEN SYNTHETIC CRUDE ULTIMATE POTENTIAL

Although the Board did not request participants to address the ultimate potential of crude bitumen, the Board provides its views in Table 3-8 and the following summary comments.

TABLE 3-8 ERCB FORECAST BITUMEN SYNTHETIC CRUDE ULTIMATE POTENTIAL millions of cubic metres

	CRUDE BITUMEN[a] MINING	CRUDE BITUMEN[a] INSITU	NET YIELD FACTOR	SYNTHETIC CRUDE[a] MINING	SYNTHETIC CRUDE[a] IN SITU
Initial Established	5350	-	0.75	4010	-
Cumulative Production	45	-		32	-
Remaining Established	5305	-		3978	-
Projected Development	2650	32 000	0.75	1990	24 000
Total Initial Potential	8000	32 000		6000	24 000
Total Remaining Potential	7955	32 000		5968	24 000

[a] ERCB Report 80-18

The Board estimates the ultimate potential of crude bitumen in-place to be 200 billion m^3. Of this total, about 25 billion m^3 lie in deposits which may eventually be amenable to surface mining operations, and about 175 billion m^3 in deeper deposits which will require underground mining or in situ recovery. The Board projects the ultimate potential from deposits suitable for surface mining to be some 8 billion m^3 of crude bitumen available in extracted form for downstream processing operations. The Board now also roughly estimates the ultimate potential for established crude bitumen reserves from the deep Cretaceous sediments to be some 32 billion m^3. Altogether, the total ultimate potential for established reserves of crude bitumen would be about 40 billion m^3.

The yield of synthetic crude oil from each barrel of crude bitumen will vary with the particular upgrading technology and depend on whether any off-site energy sources are employed. For the current estimate of ultimate potential, the Board has assumed that optimum long-term upgrading technology will have a net yield factor of 0.75 after provision for a fully energy self-sufficient operation. On this basis the ultimate potential for synthetic crude oil is estimated as 30 billion m^3, with 6 billion m^3 and 24 billion m^3, respectively, attributable to the mining and in situ areas. To the extent that energy is supplied from external sources, such as from coal, the yield of synthetic crude oil could be greater.

Crude bitumen occurrences in Paleozoic sediments, primarily in Devonian carbonates immediately below the bitumen bearing Cretaceous sediments, have not been included in the ultimate potential forecast. The quality of these occurrences and their amenability to in situ recovery techniques are uncertain, and no attempt was made to evaluate the ultimate potential of crude bitumen that may some day be derived from them.

3.5 ULTIMATE POTENTIAL SUMMARY

The Board's estimates of ultimate potential of crude oil and equivalent are summarized in Table 3-9.

TABLE 3-9 SUMMARY OF ERCB FORECAST CRUDE OIL AND EQUIVALENT ULTIMATE POTENTIAL
millions of cubic metres

	Light-Medium	Heavy	Pentanes Plus	Bitumen Synthetic		Total
				Mining	Insitu	
Initial Established[a]	1803	87	244	4 010	-	6 144
Cumulative Production[a] (79-12-31)	1081	49	119	32	-	1 281
Remaining Established[a]	722	38	125	3 978	-	4 863
Discoveries/ Additions	300	40	74	-		414
Tertiary	300	75	-	-	-	375
Future Potential	-	-	-	2 990	24 000	25 990
Total Initial Potential	2403	202	318	6 000	24 000	32 923
Total Remaining Potential (79-12-81)	1322	153	199	5 968	24 000	31 642

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[a] ERCB Report 80-18

Recent historical and the Board's 20-year forecast of annual growth patterns for various categories of crude oil are shown in Table 3-10. Figure 3-1 is a graphic presentation of the same information. The data are used in Chapter 4 for the Board's productive capacity forecast.

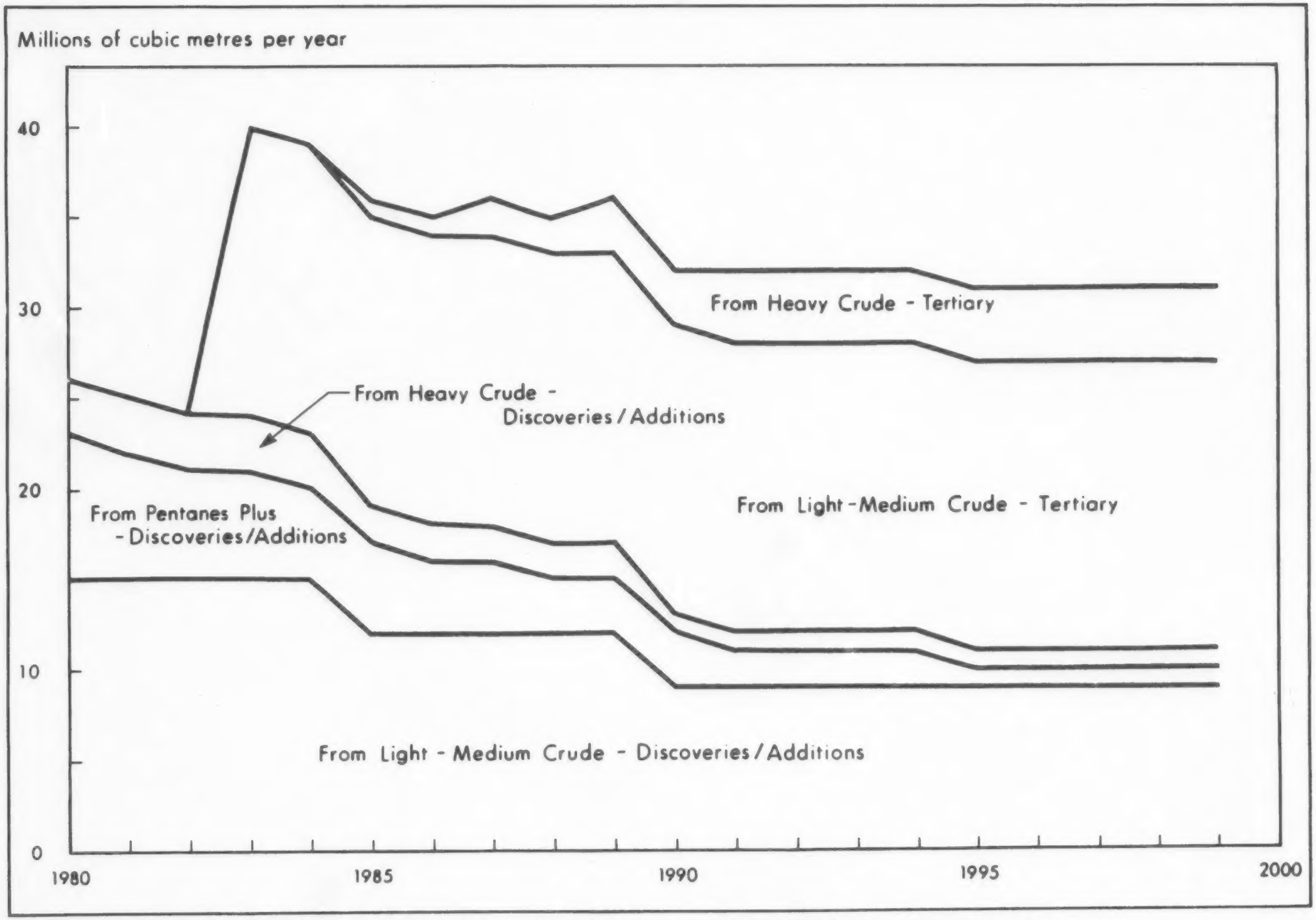


FIGURE 3-1 ERCB RESERVES GROWTH PATTERNS — LIGHT-MEDIUM, HEAVY AND PENTANES PLUS. All sources.

TABLE 3-10 SUMMARY OF ERCB RESERVES GROWTH PATTERNS
LIGHT-MEDIUM, HEAVY AND PENTANES PLUS
millions of cubic metres per year

Year	Light-Medium			Heavy			Pentanes Plus	Total
	Discoveries/ Additions	Tertiary	Total	Discoveries/ Additions	Tertiary	Total	Discoveries/ Additions	
Historical						[a]		
1970			33.5			3.3	21.5	58.3
1971			17.3			4.4	-15.5	6.2
1972			13.2			6.8	- 1.1	18.9
1973			5.1			4.0	9.9	19.0
1974			35.7			2.7	0.7	39.1
1975			1.7			5.1	- 3.8	3.0
1976			-28.1			9.5	4.9	-13.7
1977			11.1			7.9	7.0	26.0
1978			23.5			0.9	4.8	29.2
1979			30.0			4.3	8.5	42.8
Forecast								
1980	15	-	15	3	-	3	8	26
1981	15	-	15	3	-	3	7	25
1982	15	-	15	3	-	3	6	24
1983	15	16	31	3	-	3	6	40
1984	15	16	31	3	-	3	5	39
1985	12	16	28	2	1	3	5	36
1986	12	16	28	2	1	3	4	35
1987	12	16	28	2	2	4	4	36
1988	12	16	28	2	2	4	3	35
1989	12	16	28	2	3	5	3	36
1990	9	16	25	1	3	4	3	32
1991	9	16	25	1	4	5	2	32
1992	9	16	25	1	4	5	2	32
1993	9	16	25	1	4	5	2	32
1994	9	16	25	1	4	5	2	32
1995	9	16	25	1	4	5	1	31
1996	9	16	25	1	4	5	1	31
1997	9	16	25	1	4	5	1	31
1998	9	16	25	1	4	5	1	31
1999	9	16	25	1	4	5	1	31
Total Forecast	225	272	498	35	48	83	67	647

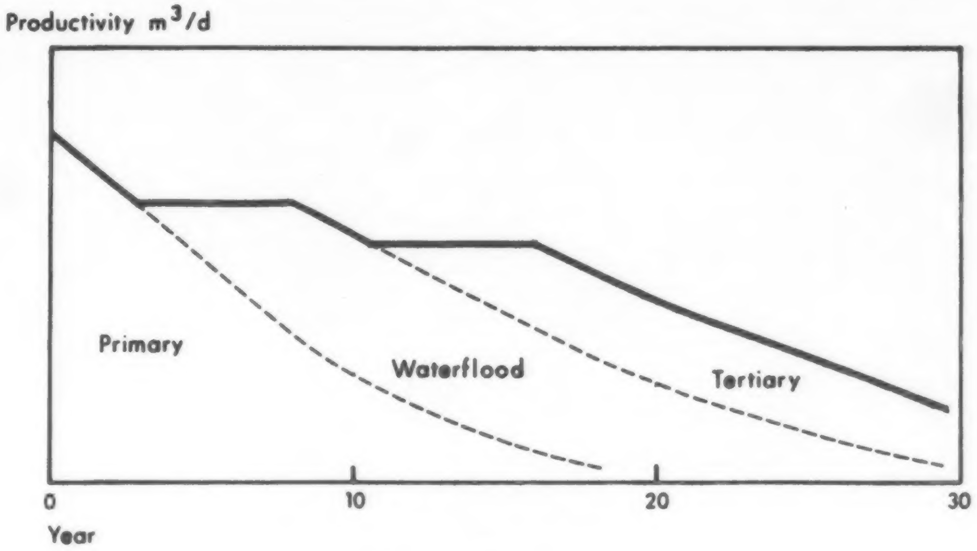
[a] Includes the lower density crude oil pools of southeastern Alberta which are marketed as heavy crude oil.

4 PRODUCTIVE CAPACITY (SUPPLY)

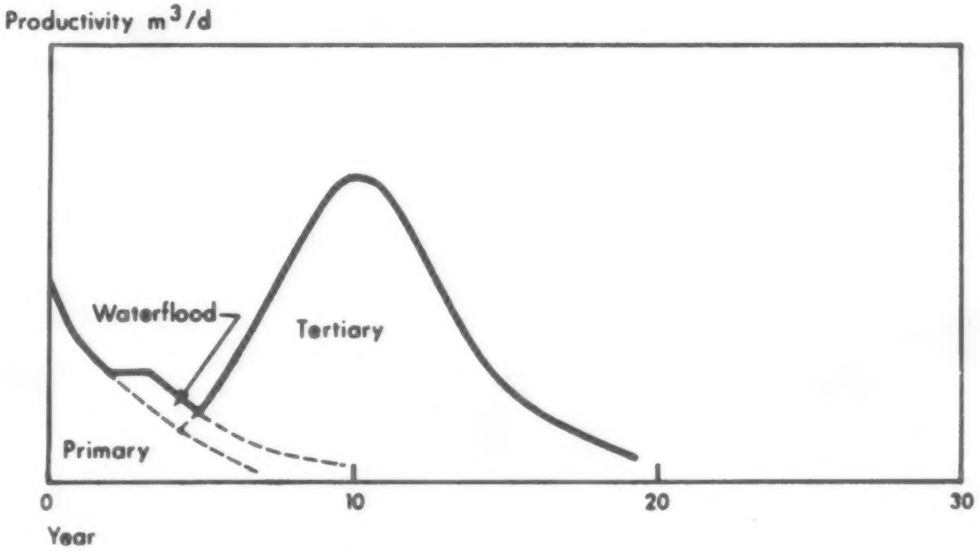
Ultimate potential is the sum of remaining established reserves, cumulative production, and reserves expected to become established in the future. It is also the sum of the production which has occurred and is projected. Ultimate potential, patterns of reservoir growth and forecasts of productive capacity are therefore inseparably linked.

Production from established reserves can be forecast reliably from past performance and engineering projections of future performance for each pool. For new reserves, whether conventional or tertiary, it is necessary to consider a number of factors which influence the rates at which those reserves will be developed and the production rates that will be achieved. Determining the supply from new discoveries involves consideration of the pace of drilling activity, the probability of new discoveries, and the likely quality of the reservoirs. Forecasts of light-medium tertiary production potential involve careful consideration of the production rate response from tertiary recovery mechanisms, economic incentives for exploiting that potential rather than other potential sources of supply, time required for field tests to prove feasibility, and the kinds of reservoirs that might be amenable to such operations. For heavy oil tertiary recovery projections, a paucity of tertiary recovery field pilot data and very limited primary reservoir production information requires that forecasts of supply lean heavily on hypothesis.

Figure 4-1 illustrates the relationship between productivity and time for primary depletion followed by waterflood and tertiary recovery. The

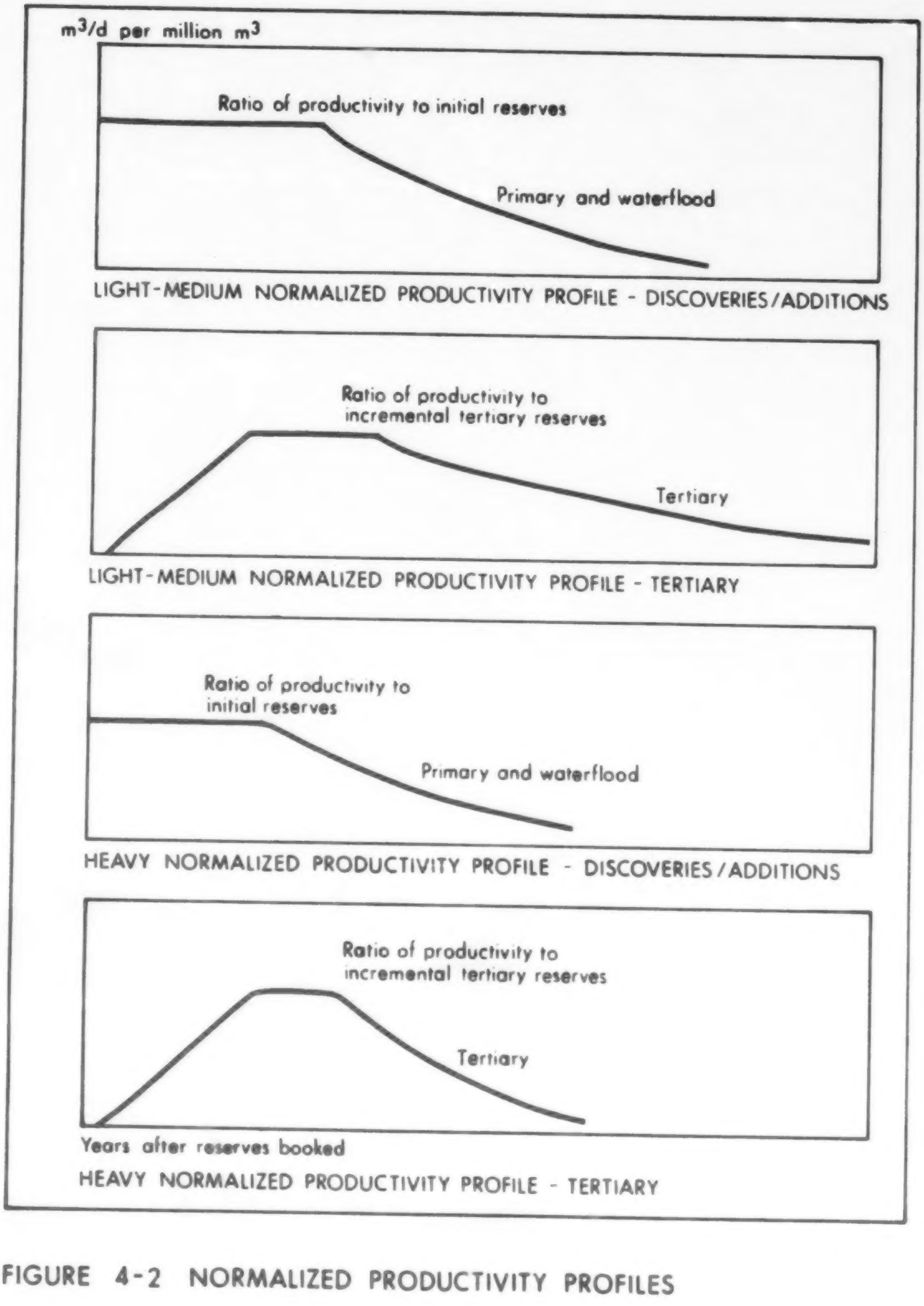


LIGHT - MEDIUM OIL RESERVOIR PRODUCTIVITY PROFILES



HEAVY OIL RESERVOIR PRODUCTIVITY PROFILES

FIGURE 4-1 SCHEMATIC OF OIL RESERVOIR PRODUCTIVITY PROFILES



LIGHT-MEDIUM NORMALIZED PRODUCTIVITY PROFILE - DISCOVERIES/ADDITIONS

LIGHT-MEDIUM NORMALIZED PRODUCTIVITY PROFILE - TERTIARY

HEAVY NORMALIZED PRODUCTIVITY PROFILE - DISCOVERIES/ADDITIONS

HEAVY NORMALIZED PRODUCTIVITY PROFILE - TERTIARY

FIGURE 4-2 NORMALIZED PRODUCTIVITY PROFILES

critical factors for each profile are: the time elapsed from start-up to achievement of response, the rate of productivity build-up, the peak rate and the rate of productivity decline. The productivity forecasts are thus related to the assigned reserves and the profiles for the particular mechanisms. Normalized productivity curves illustrating the relationships for different recovery mechanisms are shown in Figure 4-2. When applied to annual reserves increments, these yield the expected production for the respective categories of new supply.

4.1 LIGHT-MEDIUM CRUDE OIL

4.1.1 Productive Capacity of Light-Medium Remaining Established Reserves

Views of Participants

CPA and Esso forecasts of supply from light-medium established reserves are shown in Table 4-1. Petro-Canada accepted the forecasts provided in ERCB IL 80-6 (Appendix A-4). In addition, Chevron, Gulf, Esso and Home provided productivity decline forecasts for specific pools or projects for which they were the major or only operator while CPA presented productivity forecasts for all major pools.

Esso showed a "reasonable range" for its forecast of producibility from established reserves that depicted a small upside and a very significant downside range. Esso stated that factors contributing to the downside uncertainty were recent production performance and rising production costs. Recent pool performance at capacity production rates indicated that some major reservoirs are geologically more complex than previously interpreted. Esso cited as examples the Redwater D-3 and Judy Creek Beaverhill Lake A pools, where rising production costs and geologic complexity were indicating possible downward revision of reserves and productivity forecasts.

TABLE 4-1 LIGHT-MEDIUM ESTABLISHED RESERVES
PRODUCTIVE CAPACITY
thousands of cubic metres per day

Year	CPA	Esso	Petro-Canada	ERCB
1980	169	167	174	165[a]
1981	159	150	159	157[a]
1982	150	131	143	143
1983	138	119	130	130
1984	119	105	115	115
1985	104	95	103	103
1986	93	86	91	91
1987	82	79	81	81
1988	73	73	71	71
1989	66	67	63	63
1990	57	61	56	56
1991	52	56	50	50
1992	47	51	45	45
1993	42	47	40	40
1994	37	44	36	36
1995	34	40	32	32
1996	32	37	29	29
1997	30	35	27	26
1998	28	33	23	23
1999	26	31	21	21

From established reserves as of 1 January 1980, primary and all enhanced recovery (water flood and solvent)

[a] Productive Capacity for 1980 and 1981 has been adjusted downward on the basis of further production experience available to the end of September 1980.

Views of Board

The Board notes that there was substantial agreement by all participants on productive capacity from light-medium established reserves. These forecasts are an aggregate of generally fairly accurate detailed reservoir engineering forecasts for individual pools. However, the Board agrees with Esso that there is some uncertainty respecting production from the poorer parts of complex reservoirs.

The Board's forecast of production capacity is shown in column 4 of Table 4-1, and details for individual pools are provided in Appendix A-4. These forecasts are the same as those published by the Board in IL 80-6. Productive capacity for 1980 and 1981 has been adjusted downward on the basis of further production experience available to the end of September 1980.

4.1.2 Productive Capacity of Light-Medium Discoveries/Additions

CPA, Esso and Petro-Canada provided forecasts of light-medium crude oil supply from new discoveries, including extensions and additions, for the entire province. Dome forecast possible supply from new discoveries in the deep basin only. Comparison of the evidence involved consideration of the annual reserve growth patterns shown in Table 4-2 and normalized productivity profiles illustrated in Figure 4-3.

Views of CPA

CPA assumed that all of the 152 million m^3 of discoveries/additions potential would be discovered by the year 2000, and would be booked in declining annual increments that recognize the mature stage of development of the basin. The declining trend in reserves booking shown in column 1 of Table 4-2 assumed 7.5 per cent per year for 4 years, 5 per cent per year for 12 years, and 2.5 per cent for the last 4 years. Reserves discovered in a particular year were assumed to be fully booked in 5 years on a schedule of 30, 25, 20, 15 and 10 per cent in successive years.

CPA assumed that the total booked discoveries/additions for a particular year would begin producing at mid-year, and that production would commence at a reserves-to-production ratio of 14, equivalent to 195 m^3/d per million m^3 of reserves. The initial production rate would be sustained for 8 years, after which the productivity would decline as shown in Figure 4-3. CPA's forecast of light-medium productivity, from discoveries/additions, shown in Table 4-3, thus rose to 17 thousand m^3/d by 1995.

Views of Dome

Dome forecast production from the deep basin would grow to a peak of 7950 m^3 per day by 1985 and then decline to some 2600 m^3 per day for a cumulative production of 38.3 million m^3. Dome considered this forecast to be conservative.

Views of Esso

Esso assumed that three-quarters of the 320 million m^3 discoveries/additions ultimate potential which it forecast for the light-medium crude oil category would be found in the next 20 years. Its finding rate curve for undiscovered potential was based on projected drilling activity and historical trends of success ratios. Growth was projected by assuming that reserves discovered in a given year would be developed over a six-year period: 10, 15 and 15 per cent in each of the first three years and 20 per cent each year for the next three years, resulting in the growth pattern shown in Table 4-2. Each annual reserves total was assumed to have a production profile with an initial peak plateau of 160 m^3/d per million m^3 of reserves which would be sustained until 30 per cent of the reserves were depleted and then decline at 8 per cent per year. The profile in normalized form is shown in Figure 4-3.

The Esso forecast, in column 2 of Table 4-3, shows productivity from light-medium discoveries/additions rising to 24 thousand m^3/d by 1991. Also Esso provided a range above and below its most probable productivity forecast to reflect an uncertainty of 50 per cent in the rate of finding and developing new reserves.

Views of Petro-Canada

Petro-Canada arbitrarily assumed that its light-medium crude oil discoveries/additions potential of 284 million m^3 would develop on an annual growth pattern of some 20.7 million m^3 until 1986, after which the annual development rate would decline linearly to 3.75 million m^3 by the end of the forecast period, as shown in Table 4-2.

Petro-Canada prepared a productivity profile for each major producing geologic horizon, using ERCB detailed pool productivity decline data (IL 80-6). Its composite normalized profile for all horizons is shown in Figure 4-3. The decline curve data were applied to the reserves growth profile for the forecast period for each geologic horizon, and then summed to determine forecast for the province. The resulting supply data shown in Table 4-3 indicate productivity from new sources of light-medium crude oil climbing fairly rapidly and reaching a peak of 47 thousand m^3/d by 1992.

Views of the Board

The Board considers the CPA forecast of light-medium reserves growth to be conservative, and believes Petro-Canada's to be optimistic when viewed in light of reserves growth over the last ten years. The Board chose to start its reserves growth pattern at 15 million m^3 per year, similar to recent historical reserves growth, and declined it in two steps over the forecast period in order to achieve production of three-quarters of the remaining ultimate potential by the year 2000. The result is broadly similar to Esso's forecast.

TABLE 4-2 LIGHT-MEDIUM DISCOVERIES/ADDITIONS
RESERVES GROWTH PATTERNS
millions of cubic metres per year

Year	CPA	Esso	Petro-Canada	ERCB
1980	11.32	34	20.66	15
1981	11.32	28	20.66	15
1982	11.32	23	20.66	15
1983	11.32	19	20.66	15
1984	7.55	16	20.66	15
1985	7.55	14	20.42	12
1986	7.55	12	19.23	12
1987	7.55	11	18.04	12
1988	7.55	10	16.92	12
1989	7.55	10	15.65	12
1990	7.55	9	14.46	9
1991	7.55	8	13.27	9
1992	7.55	7	12.08	9
1993	7.55	7	10.88	9
1994	7.55	7	9.69	9
1995	7.55	6	8.50	9
1996	3.73	6	7.31	9
1997	3.73	5	6.12	9
1998	3.73	5	4.93	9
1999	3.73	5	3.75	9
	151	242	285	225

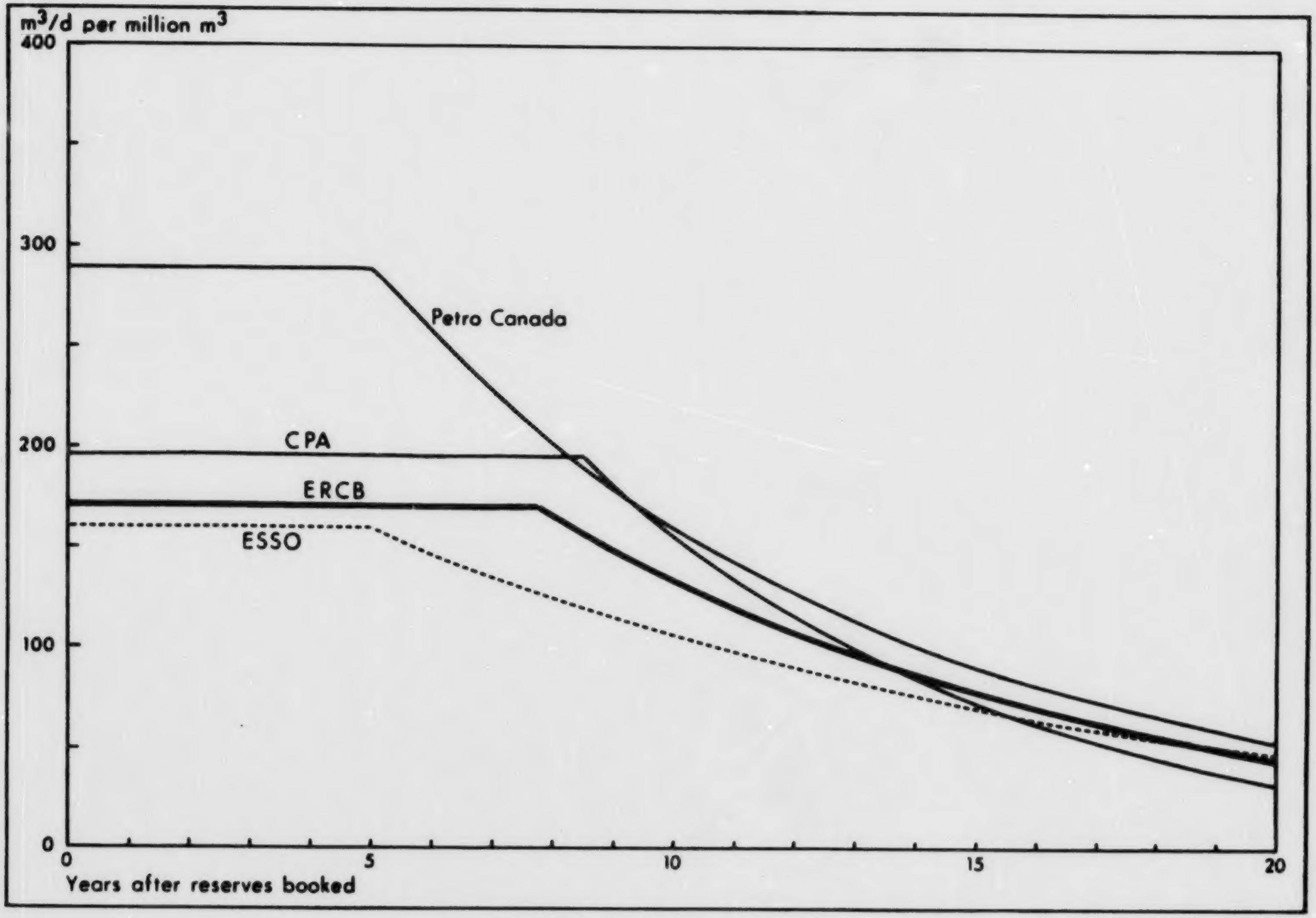


FIGURE 4-3 LIGHT-MEDIUM OIL NORMALIZED PRODUCTIVITY PROFILES — DISCOVERIES/ADDITIONS. Comparison of submitted and ERCB profiles.

TABLE 4-3 LIGHT-MEDIUM DISCOVERIES/ADDITIONS
PRODUCTIVE CAPACITY
thousands of cubic metres per day

Year	CPA	Esso	Petro-Canada	ERCB
1980	-	1	1	1
1981	1	2	6	4
1982	3	4	12	6
1983	4	6	18	9
1984	6	10	24	11
1985	8	13	29	14
1986	9	17	34	16
1987	11	19	38	19
1988	12	21	41	19
1989	13	22	44	21
1990	14	23	46	22
1991	15	24	46	23
1992	16	24	47	23
1993	16	24	47	24
1994	16	24	46	24
1995	17	24	45	24
1996	17	24	43	24
1997	17	23	41	24
1998	17	23	39	24
1999	17	22	37	24

From reserve growth - primary and waterflood

Normalized productivity profiles of all participants are shown in Figure 4-3. The Board observes that Petro-Canada's profile is technically in error because the area under the profile, the sum of production, exceeds the booked reserves.

Based on previous studies and some new work by Board staff, the Board finds that Alberta pools have initial rates ranging from 200 to 600 m^3/d per million m^3 of primary reserves, with a mean of approximately 300 m^3/d per million m^3. Recognizing that the discoveries/additions ultimate potential includes reserves attributed to waterflood schemes in future pools, and further recognizing that waterflooding will sustain reservoir productivity as illustrated in Figure 4-1, the Board considers a peak rate productivity of 170 m^3/d per million m^3 of reserves reasonable for a weighted mix of primary and waterflood reserves.

The Board's normalized productivity profile, shown in Figure 4-3, lies more or less mid-way between those of Esso and CPA. Applying this profile to the annual reserves growth additions leads to the Board's estimate, in column 4 of Table 4-3. This shows sustained growth of new supplies of light-medium crude, with productive capacity reaching 24 thousand m^3/d by 1993 and remaining at that level to the end of the forecast period, a result similar to Esso's.

4.1.3 Productive Capacity of Light-Medium Tertiary

The CPA, Esso and IPAC forecasts of annual reserves growth and productive capacity from future light-medium tertiary recovery schemes are shown in Tables 4-4 and 4-5 respectively. Normalized productivity profiles for these forecasts are presented in Figure 4-4. Dome and Home did not present a provincial forecast, but offered views on individual pools or parts of the province.

Views of CPA

As shown in Table 4-4, CPA forecast a very aggressive light-medium tertiary development pattern in the period 1985 to 1989. Projects forecast to commence in this period would be in existing pools and contribute 295 million m^3 of the 312 million m^3 expected from tertiary recovery.

The normalized tertiary productivity profile used by CPA, shown in Figure 4-4, was applied to its annual reserve growth pattern to obtain the light-medium tertiary productive capacity forecast in Table 4-5. The rapid tertiary development allows the production response to climb rapidly to a peak of 44 thousand m^3/d by 1993.

CPA estimated that 720 infill wells, mainly injectors, would be required to implement its forecast tertiary programs. It emphasized that the projections assumed strong economic incentives for development of tertiary projects and pointed out that, if that were the case, shortages of technical personnel might force some deferment of developments. On the other hand, without significant economic incentives, tertiary operations would remain very limited and contribute only modest increments of oil supply.

Views of Dome

From its assessment of the Pembina Cardium pool, Dome, as previously noted, indicated that the pool's tertiary potential was as high as 237 million m^3. The capital cost of attaining that level of incremental recovery was estimated to be \$35 billion (1978 dollars) for a CO_2 flood. Although Dome did not submit an estimate of the number of infill wells required to operate the CO_2 flood, its production forecasts indicated that some six years after the start of operations, output from the field would be approximately 28 thousand m^3/d, compared to approximately 7 thousand m^3/d for the base case of primary plus waterflood operation. By inference the required infill wells would be three to four times the current total of 3000 producing wells. Dome's analysis indicated that a netback of 125 $\$/m^3$ (1978 dollars) would be required to achieve the estimated level of incremental recovery.

Dome postulated that miscible flood operations in the deep basin could recover some 890 million m^3, mostly from the Dunvegan and Lower Cardium sands. The well density for such operations could be 8 to 16 wells per section over 45 townships.

Dome did not provide a productive capacity forecast for tertiary potential in the deep basin, and had not considered potential from the Lower Cardium sand because exploration and development activity in the deep basin is still speculative. It was quite certain that a potential of 38 million m^3 (discussed under discoveries/additions) could be realized and forecast a peak rate of some 8 thousand m^3/d by 1985 from the deep basin.

Views of Esso

Esso projected a light-medium tertiary reserves growth pattern, as shown in Table 4-4, on the assumption that current revenue sharing and the current world price of 220 $\$/m^3$ would apply. Combining the annual increments with the normalized productivity profile outlined in Figure 4-4[1] resulted in the productive capacity forecast shown in Table 4-5.

This forecast reflects the long lead-time associated with feasibility studies, necessary laboratory and field pilot tests, development drilling and facility construction. Esso emphasized that improved pricing and appropriate revenue-sharing would be required to achieve the forecast.

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[1] This is the tertiary incremental profile Esso presented for the CO_2 scheme proposed for the Judy Creek Beaverhill Lake A pool.

Uncertainty over future pricing and revenue sharing policies, recent trends of costs for facilities and the risk of poor production response could reduce its forecast of light-medium tertiary productivity by 50 per cent. On the other hand, Esso judged that technological advances, consistently good response and improved netbacks to the producer could increase the forecast by 50 per cent.

Esso pointed out that its tertiary productivity forecast was significantly higher than shown in its 1978 submission to the National Energy Board because of current optimism respecting the potential of tertiary projects and recent real increases in world crude oil prices.

Views of Gulf

The Gulf-operated pools discussed under light-medium tertiary ultimate potential could, in Gulf's view, result in an incremental reserves growth of 11.5 million m^3. Gulf estimated that the incremental productivity from these reserves, beginning in 1983, could increase to some 1900 m^3/d by 1992 and decline thereafter to 1050 m^3/d in 2000.

Views of Home

Home presented productivity schedules for a possible miscible project in the Swan Hills field which showed an incremental productivity of 403 m^3/d in 1985 increasing to 2100 m^3/d in 1993 and reaching 2500 m^3/d by 2000. It noted that the forecast demonstrates the substantial benefits that could accrue from tertiary recovery and the lengthy period necessary to produce tertiary oil.

Views of IPAC

The IPAC submission demonstrated, as shown below, that possibilities for additional oil production from tertiary sources are strongly affected by the netback to producers.

Netback $/m	Tertiary Reserves million m^3	Peak Productivity thousand m^3/day	Year of Peak Response
50	16	9	1991
75	253	58	1995
100	285	66	1995
150	433	96	1995
No limit	610	116	1996

Figure 4-5, taken from the IPAC submission, demonstrates the substantial capital investments and the large impact of operating costs. IPAC emphasized that two to three years of lead-time are required to design and install a tertiary scheme (reflected in the growth pattern), two further years are required to achieve production response, and ten years elapse thereafter before full or peak production is reached. These combined effects are depicted in Figure 4-6, taken from the IPAC submission. Having regard for the cost of development, availability of material and labour, and government policies, IPAC assumed that 8.5 per cent of the tertiary ultimate potential would be produced each year. The resulting reserves growth pattern for the 150 $/m^3 netback case shown in Table 4-4 reflects additions of 36 million m^3 per year over 12 years, for an aggregate potential of some 433 million m^3. IPAC's normalized productivity profile[1], reproduced in Figure 4-4, shows a sustained production incline over a ten-year period to a peak of 220 m^3/d per million m^3 of tertiary reserves.

Table 4-5 shows the resultant productivity forecast for IPAC's 150 $/m^3 netback case, with total light-medium tertiary production rising rapidly to a level of 64 thousand m^3/d by 1990 and a peak rate of 96 thousand m^3/d

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[1] IPAC did not provide specific details on its method of forecasting productivity profiles for tertiary mechanisms, but from replies to questions at the hearing and data provided to the Board following the hearing, a profile was estimated.

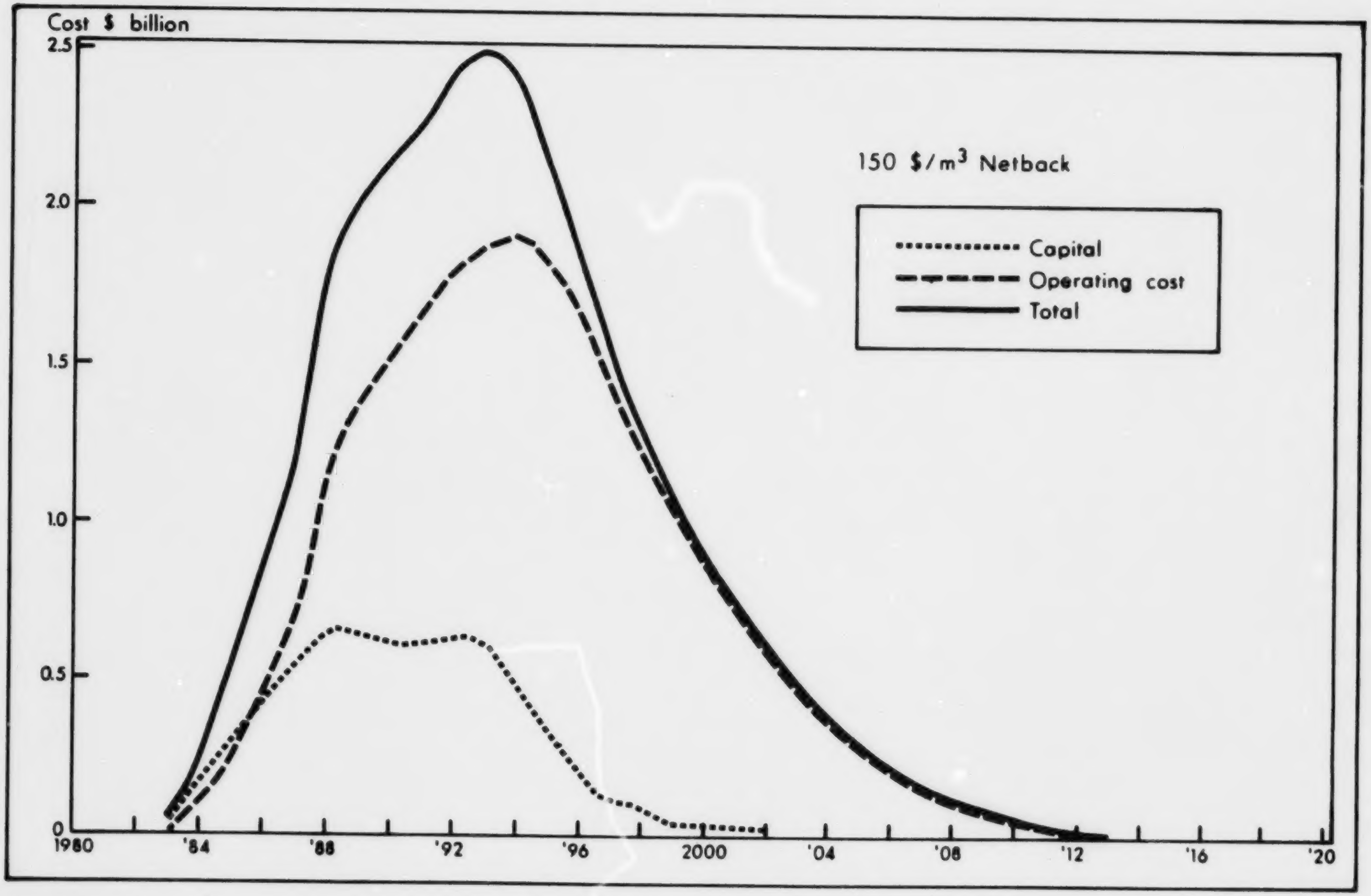

FIGURE 4-5 LIGHT - MEDIUM TERTIARY RECOVERY COST DATA.
Copied from IPAC submission (appendix I - figure 11)

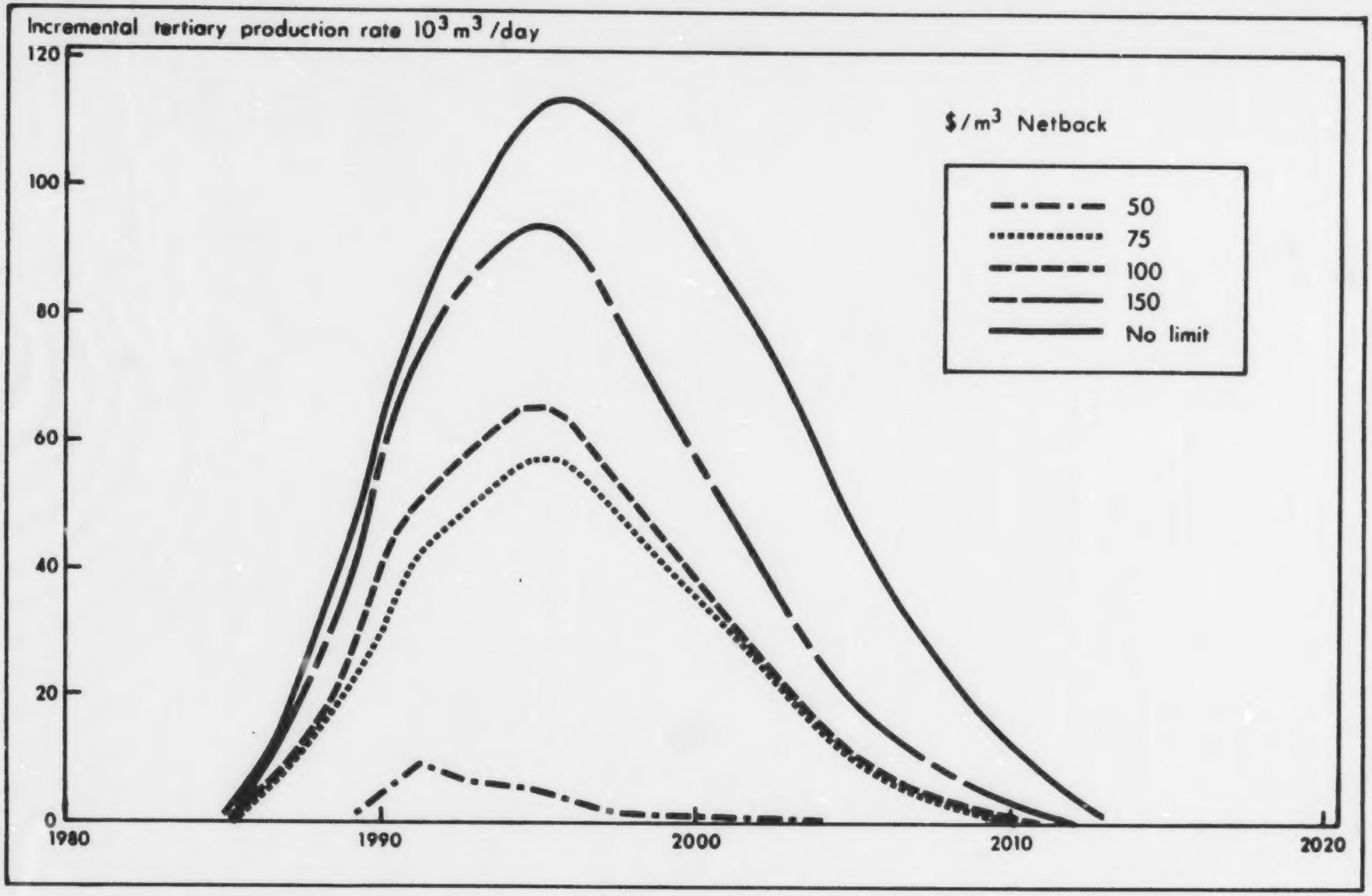

FIGURE 4-6 LIGHT - MEDIUM TERTIARY PRODUCTIVITY vs NETBACK.
Copied from IPAC submission (appendix I - figure 5)

by 1995. Most of the productivity accrues from tertiary projects in the Keg River, Gilwood and Beaverhill Lake pools as described in Chapter 3.

Views of Petro-Canada

Petro-Canada stated that under present pricing and fiscal regimes, tertiary recovery schemes are usually economically unattractive. It added that unless the technical and economic problems associated with tertiary recovery can be overcome soon, tertiary recovery is unlikely to make a significant contribution before the late 1980s. Accordingly, Petro-Canada's forecast of tertiary productivity from both light-medium and heavy crude oil showed a gradual build-up to 34 thousand m^3 by 2000. No details of the pattern of reserves growth, productivity profiles or the distribution of forecast productivity between light-medium and heavy crude oil were provided.

Views of the Board

The Board notes that the tertiary potential is intimately linked with the rate of production response that can be achieved and the capital investments and operating costs associated with the operation. The IPAC submission is a good illustration of these links. The shape of the normalized production response profile therefore takes on extraordinary significance for the tertiary recovery estimates. The Board adopted a profile, shown in Figure 4-4, in which the production response builds up over approximately a four-year period in a manner not unlike that of IPAC and CPA. The Board concluded, however, that typical peak response for a reasonably efficient light-medium tertiary scheme would be not more than about 120 m^3/d per million reserves, somewhat lower than suggested by CPA and considerably lower than used by IPAC in its forecast. By comparison Esso thought that the initial peak rate of its normalized profile for the Judy Creek CO_2 scheme would be about 60 m^3/d per million of reserves.

TABLE 4-4 LIGHT-MEDIUM TERTIARY
RESERVES GROWTH PATTERNS
millions of cubic metres per year

Year	CPA	Esso	IPAC[a]	ERCB
1980	-	-	-	-
1981	-	-	-	-
1982	.1	-	-	-
1983	.3	39	36	16
1984	-	-	36	16
1985	139.2	11	36	16
1986	1.9	8	36	16
1987	80.9	34	36	16
1988	1.9	-	36	16
1989	73.0	8	36	16
1990	1.3	15	36	16
1991	1.3	41	36	16
1992	1.3	8	36	16
1993	1.3	17	36	16
1994	1.3	-	36	16
1995	1.3	38	-	16
1996	1.3	17	-	16
1997	1.3	-	-	16
1998	1.3	-	-	16
1999	1.3	46	-	16
	312	282	432	272

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[a] 150 $/m^3 netback case

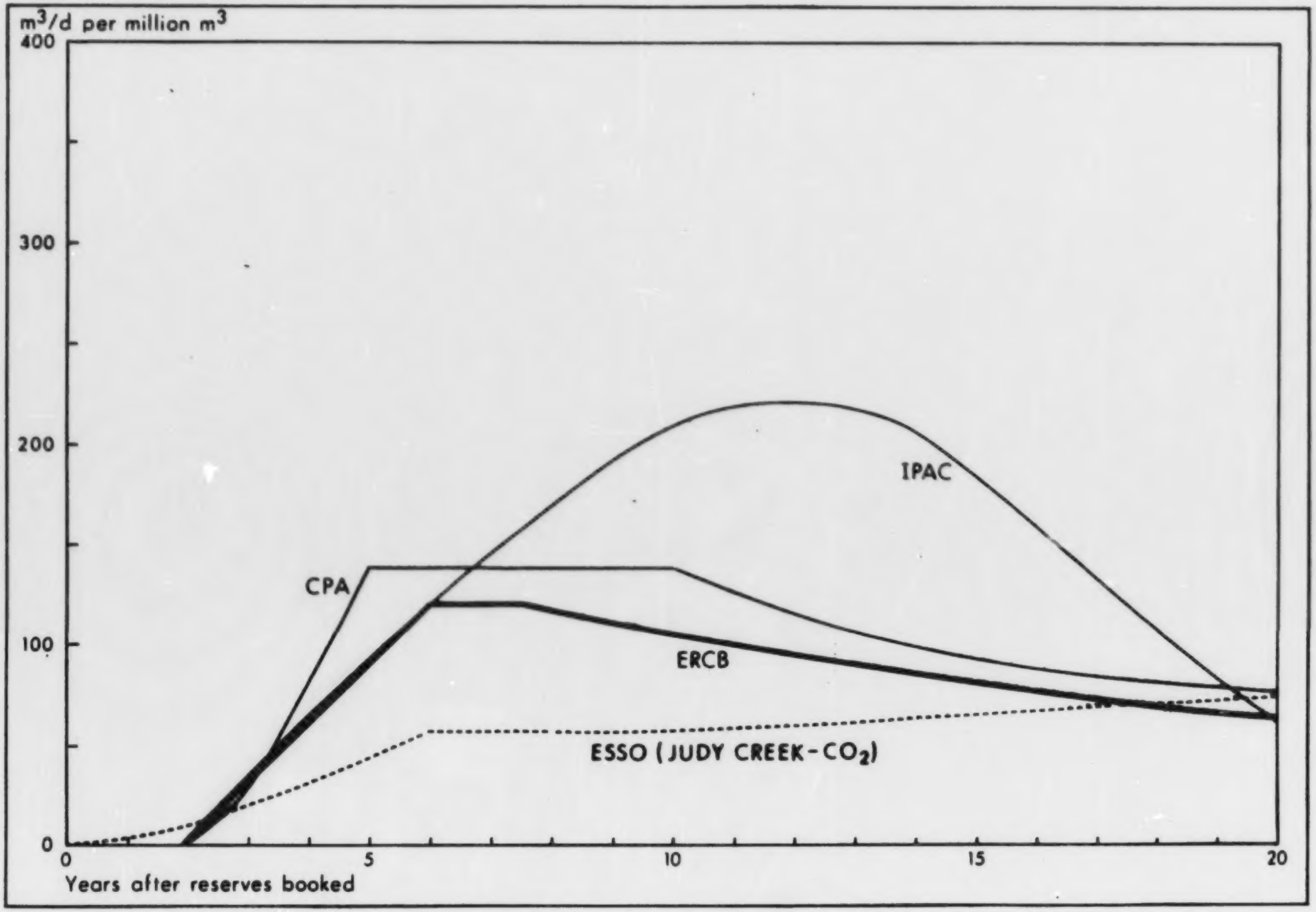

FIGURE 4-4 LIGHT-MEDIUM OIL NORMALIZED PRODUCTIVITY PROFILES — TERTIARY
Comparison of submitted and ERCB profiles.

TABLE 4-5 LIGHT-MEDIUM TERTIARY
PRODUCTIVE CAPACITY
thousands of cubic metres per day

Year	CPA	Esso	IPAC[a]	ERCB
1980	-	-	-	-
1981	-	-	-	-
1982	*	-	-	-
1983	1	2	-	*
1984	2	4	-	1
1985	3	5	1	3
1986	4	8	7	5
1987	7	10	15	7
1988	15	11	27	9
1989	23	12	43	12
1990	30	14	64	13
1991	35	14	76	14
1992	40	15	83	15
1993	44	18	88	17
1994	44	18	94	17
1995	44	19	96	19
1996	43	20	93	20
1997	41	21	86	22
1998	38	21	76	23
1999	35	22	66	24

---

[a] 150 $\$/m^3$ net back case.
* Less than 1000 m^3/d.

With reference to reserves growth patterns for light-medium tertiary Table 4-4, the Board believes that allowances must be made for field pilot testing and for designated construction of projects. For its forecast, the Board simply assumed that there would be a continuum of tertiary projects coming on stream beginning in 1983, with each annual reserves increment being 16 million m^3, equivalent to two-thirds the amount for the Judy Creek A pool CO_2 scheme. This results in about 90 per cent of the Board's estimate of total tertiary light-medium potential being on stream by 1999. The Board believes that the developments reflected in the CPA forecast of tertiary reserves growth are unrealistically rapid because they imply installation of almost all tertiary projects between 1985 and 1989. By comparison the forecast presented by Esso in Table 4-4 seems more plausible. Similarly, IPAC's forecast indicates that the bulk of the tertiary projects will be brought on stream between 1983 and 1994 is not unreasonable in terms of timing, but appears overstated in terms of quantities of tertiary reserves. The Board agrees with IPAC that most of the tertiary potential is in the Keg River, Gilwood and Beaverhill Lake pools. The Board considers the Dome estimates of tertiary potential in the Cardium and Dunvegan sands to be conceptual only and of doubtful economic viability except for some parts of the Pembina Cardium Pool.

Applying its normalized productivity profile to the tertiary reserves growth pattern shown in Table 4-4, the Board developed the forecast of productive capacity set out in Table 4-5. The results show the production response from light-medium tertiary projects gradually climbing to an incremental production of 14 thousand m^3/d by 1990 and to 25 thousand m^3/d by 1999. Although the Board does not believe the IPAC production forecast for the 150 $\$/m^3$ netback case to be attainable, it nevertheless considers the information provided by IPAC helpful insofar as it relates to estimates of capital investments and operating costs. This information stresses an important, but not always appreciated, aspect of tertiary oil reserves, i.e. that combined

TABLE 4-6 HEAVY ESTABLISHED RESERVES
PRODUCTIVE CAPACITY
thousands of cubic metres per day

Year	CPA	Esso	Petro-Canada	ERCB
1980	14	13	14	14
1981	12	12	12	12
1982	11	11	10	10
1983	9	10	9	9
1984	8	9	8	8
1985	7	8	7	7
1986	7	8	6	6
1987	6	7	5	5
1988	5	6	5	5
1989	5	6	4	4
1990	4	5	4	4
1991	4	4	3	3
1992	4	4	3	3
1993	3	4	2	2
1994	3	3	2	2
1995	3	3	2	2
1996	3	2	1	1
1997	2	2	1	1
1998	2	2	1	1
1999	2	2	1	1

From established reserves as of 1 January 1980 "levelized" capital and operating costs for developing such reserves approximate those associated with comparatively high cost bitumen synthetic crude projects. The Board therefore concludes that many tertiary projects cannot proceed without something near current world prices and access to special royalty reductions such as those provided for in Section 4.2 of the Alberta Royalty Regulations.

4.2 HEAVY CRUDE OIL

4.2.1 Productive Capacity of Heavy Remaining Established Reserves

Views of Participants

CPA, Esso and Petro-Canada provided forecasts of productive capacity for the entire province from remaining established reserves of conventional heavy crude oil as shown in Table 4-6. Petro-Canada accepted the productive capacity forecast given by the Board prior to the hearing. Husky confined its submission to productivity decline forecasts for specific pools in the Lloydminster area.

Views of the Board

As illustrated in Table 4-6 there is good agreement among participants on provincial heavy crude productivity from established reserves. The Board's forecast of established heavy crude productivity is shown in column 4. Details of forecasts of individual pools are provided in Appendix A-4.

4.2.2 Productive Capacity of Heavy Discoveries/Additions

CPA, Esso and Petro-Canada provided productivity forecasts from heavy crude oil discoveries/additions for the entire province, as shown in Table 4-8. Dome presented forecasts of supply from new discoveries in two specific areas: southeastern Alberta and Lloydminster.

The annual reserves growth patterns and normalized productivity profile of participants are outlined in Table 4-7 and Figure 4-7 respectively.

Views of CPA

CPA projected productivity from discoveries/additions of conventional heavy crude in essentially the same manner as for light-medium crude oil. It provided a reserve growth pattern in which declining increments, added over the forecast period, lead to an ultimate potential of 40 million m^3. Reserves credited to a given year were assigned the productivity profile shown in Figure 4-7. The summation of these forecasts resulted in the productivity forecast set out in Table 4-8 where conventional heavy oil productivity is shown to gradually climb to a level of 5 thousand m^3/d by 1995.

Views of Dome

Dome extended its 72 million m^3 estimate of the heavy discoveries/additions potential for southeastern Alberta into a supply estimate by assuming a constant 3.6 million m^3 per year growth pattern and productivity corresponding to the ERCB maximum rate limit (MRL) formula. By the year 2000, productivity from these reserves were thus forecast to reach some 11 thousand m^3/d as shown in Table 4-8.

Although Dome did not provide a heavy crude discoveries/additions reserves growth pattern for Lloydminster, it provided the following productivity estimates:

	Discoveries/Additions			
Netback 1980 $/$m^3$	Potential million m^3	Productivity by 1999 thousand m^3/d	Number of Wells Required	Minimum Initial Well Productivity m^3/d/well
227	87	15.4	21 400	0.8
115	76	12.2	13 600	1.6
82	48	7.2	6 000	2.4
64	15	2.4	1 600	3.2

The detailed forecast for the 115 $/m^3 netback case, in Table 4-8 shows productivity of 12 thousand m^3/d by the year 1999. This case calls for 13 600 wells to be drilled on eight hectare spacing. Dome considered the forecast rate to be attainable on the basis that initial productivity of wells at Lloydminster average 3 m^3/d.

Views of Esso

Esso did not provide a reserves growth pattern or productivity profile for its forecast 30 million m^3 of heavy discoveries/additions potential. The productive capacity attributed to these reserves, shown in column two of Table 4-8, shows a peak of 5 thousand m^3/d reached by 1985.

Views of Petro-Canada

Petro-Canada forecast that the heavy discoveries/additions reserves growth pattern would continue at a constant 4.77 million m^3 per year over the 20-year forecast period, reflecting its relative optimism for heavy oil developments.

Petro-Canada prepared heavy crude oil productivity profiles for each major geologic horizon, using pool productivity declines determined from ERCB data (IL 80-6). These profiles, for which a composite normalized productivity profile is shown in Figure 4-7, were combined with the recoverable reserves growth profile for the forecast period for each geologic horizon to provide the cumulative forecast of supply. The result, in column 3 of Table 4-8, shows productivity climbing rapidly to 13 thousand m^3/d by 1989 and continuing upward to the end of the forecast period.

Views of the Board

The Board notes that the heavy discoveries/additions and productive capacity forecasts provided by the participants, Table 4-8, differ considerably and reflect differing views respecting heavy crude oil ultimate potential. The CPA and Esso forecasts are more conservative than the others.

For reasons stated in Section 3.2.2, the Board considers the Petro-Canada and Dome forecasts to be too high. In particular, the Board notes that in both cases, the productivity forecasts have not been properly accounted against reserves growth and that forecast productivity consumes more than the available potential.

In developing its forecast, the Board assumed that 35 million m^3 of the heavy crude discoveries/additions (85 per cent of total potential) would be developed in the next 20 years. Experience in the recent past, as shown in Table 3-10, indicates heavy discoveries/additions of 4 to 5 million m^3 per year. After deleting some of the lighter density crude oil pools in southeastern Alberta, the historical growth is 3 to 4 million m^3 per year. The Board forecasts a continuation of this growth pattern for five years, followed by a decline to one million m^3 per year by the end of the 20-year forecast period as shown in Table 4-7.

Based on previous studies and some recent data, the Board observes that heavy crude oil pools have initial production rates ranging from 200 to 600 m^3/d per million m^3 of primary reserves. Assuming that one-quarter of heavy discoveries/additions contain a component of waterflood reserve contributions, as illustrated by Figure 4-1, the Board considers a peak rate productivity of 250 m^3/d per million m^3 of reserves to be reasonable. Referring to Figure 4-5, this is less than Petro-Canada's composite peak rate of some 330 m^3/d per million m^3

TABLE 4-7 HEAVY DISCOVERIES/ADDITIONS
RESERVES GROWTH PATTERNS
millions of cubic metres per year

Year	CPA	Petro-Canada	ERCB
1980	2.19	4.77	3
1981	2.19	4.77	3
1982	2.19	4.77	3
1983	2.19	4.77	3
1984	1.99	4.77	3
1985	1.99	4.77	2
1986	1.99	4.77	2
1987	1.99	4.77	2
1988	1.99	4.77	2
1989	1.99	4.77	2
1990	1.99	4.77	1
1991	1.99	4.77	1
1992	1.99	4.77	1
1993	1.99	4.77	1
1994	1.99	4.77	1
1995	1.99	4.77	1
1996	1.99	4.77	1
1997	1.79	4.77	1
1998	1.79	4.77	1
1999	1.79	4.77	1
	40	95	35

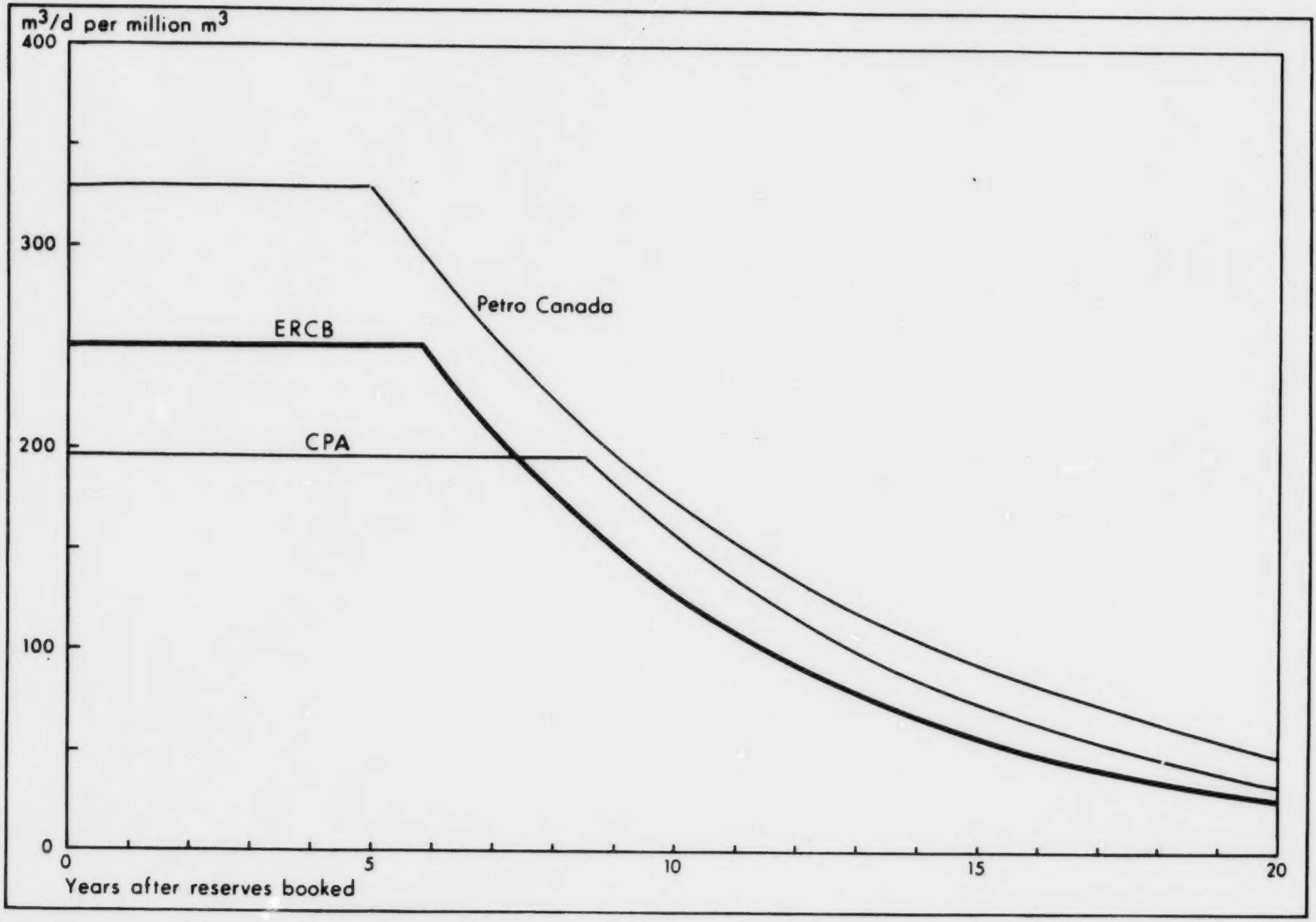

FIGURE 4-7 HEAVY OIL NORMALIZED PRODUCTIVITY PROFILES — DISCOVERIES/ADDITIONS.
Comparison of submitted and ERCB profiles.

TABLE 4-8 HEAVY DISCOVERIES/ADDITIONS
PRODUCTIVE CAPACITY
thousands of cubic metres per day

Year	CPA	Esso	Petro-Canada	Dome		ERCB
				SE Alta	Lloydminster[a]	
1980	*	1	*	1.2	1.4	*
1981	1	1	2	1.8	2.7	1
1982	1	2	3	2.5	3.8	2
1983	1	3	5	3.5	4.8	3
1984	2	4	6	4.5	5.7	3
1985	2	5	8	5.2	6.5	4
1986	3	5	9	5.8	7.2	4
1987	3	5	11	6.4	7.9	5
1988	3	5	12	7.0	8.4	5
1989	4	5	13	7.5	9.0	5
1990	4	5	13	8.0	9.5	5
1991	4	5	14	8.4	9.8	5
1992	4	4	15	8.8	10.3	5
1993	4	4	15	9.2	10.6	4
1994	5	4	16	9.2	11.0	4
1995	5	3	16	9.6	11.3	4
1996	5	3	17	9.9	11.6	4
1997	5	3	17	10.2	11.8	4
1998	5	2	17	10.5	11.9	4
1999	5	2	18	10.8	12.2	3

---

[a] 115 $\$/m^3$ netback case
* Less than 1000 m^3

of reserves, but more than the 195 m^3/d per million m^3 used by CPA. Adopting the 250 m^3/d per million m^3, the Board used a 15 per cent decline to establish its normalized profile shown in Figure 4-7.

Applying this profile to the reserves growth pattern yields the productivity forecast shown in Table 4-8. The Board believes that this forecast could be subject to some upward adjustment if the pace of heavy oil development were to surge ahead more rapidly than has been experienced in the recent past. The Board also observes that a somewhat higher and more sustained rate of production than it has forecast in this category would be required to promote development of heavy oil upgrading facilities.

4.2.3 Productive Capacity of Heavy Tertiary

As mentioned in the introduction to this chapter, the time periods required for tertiary project planning, implementation and initial operation, and the production response profile significantly affect the economic feasibility. These must be reflected in the reserves growth pattern and normalized productivity profiles used in preparing productive capacity forecasts. Further, the Board believes that paucity of heavy oil tertiary field pilot data as well as limited primary and waterflood heavy oil productivity data increases the uncertainty in the forecast considerably.

Views of CPA

Assuming a favourable economic climate and minimal development constraints, CPA forecast a rapid pace of heavy tertiary development commencing in 1983 as shown in Table 4-9. It expected that most of its forecast heavy tertiary ultimate potential of 170 million m^3 would be developed by 1991. CPA applied a normalized productivity profile, outlined in Figure 4-8, to the projected reserve growth pattern and obtained the provincial productivity forecast shown in Table 4-10. The rapid reserves growth pattern resulted in significant heavy tertiary productivity, 20 thousand m^3/d by 1990, even with the long lag at the start of the 1980s and the slow response depicted by the productivity profile.

Views of Dome

Dome submitted the following productive capacity estimates from tertiary heavy oil for the Lloydminster area:

	Tertiary (Thermal)			
Netback 1980 $/$m^3$	Incremental Potential million m^3	Incremental Productivity by 1999 thousand m^3/d	Incremental Number of Wells Required	Minimum Initial Well Productivity m^3/d/well
227	143	16.4	9 000	0.8
115	142	16.4	9 000	1.6
82	112	13.1	6 480	2.4

The detailed incremental tertiary productivity forecast for the 115 $/$m^3$ netback case, in Table 4-10, would require 9 thousand additional wells drilled on eight hectare spacing. Dome assumed in situ combustion for sands up to 3 metres thick and steam stimulation for thicker sands.

Views of Esso

Esso projected a very modest heavy tertiary reserve growth as shown in Table 4-9 because, in its view, very few areas have sufficiently thick pay sections and absence of bottom water necessary for successful tertiary recovery projects. Esso's forecast of heavy tertiary productive capacity therefore shows a relatively modest peak level of 4 thousand m^3/d by 1987.

Views of Husky

Husky forecast a heavy tertiary reserves growth pattern, as shown in Table 4-9 for the 7 schemes in the Lloydminster and Wainwright areas to which it attributed a tertiary potential of 21 million m^3. The productivity forecast for the 7 schemes is shown in Table 4-10. While expressing considerable optimism for tertiary potential relative to that for discoveries/additions, Husky cautioned, as reflected in its reserve growth patterns, that considerable pilot work is necessary before commencing full scale schemes. Husky pointed out that it had previously considered development of upgrading facilities, but had now come to the conclusion that capability to produce the oil would have to be established before upgrading plants could be seriously pursued.

Views of IPAC

IPAC stated that, with continuous intensive pilot testing, tertiary recovery in heavy oil pools could become technically viable by the mid-1980s. It assumed a very aggressive reserves growth pattern, as shown in Table 4-9. All of its potential reserves were attributed to the Mannville formation, and booked in the years 1985, 1986 and 1987. IPAC's qualitative normalized productivity profile,[1] shown in Figure 4-8, result in the peak productive capacity forecasts under various producer netbacks shown below. The detailed forecast for the 150 $/$m^3$ netback case is shown in Table 4-10.

---

[1] IPAC did not provide specific details on its method of forecasting productivity profiles for tertiary mechanisms, but from replies to questions at the hearing and data provided to the Board subsequent to the hearing, a profile was estimated.

Netback $/m	Recoverable Reserves million m^3	Maximum Productivity thousand m^3/d	Year of Occurrence
50	18	3.8	1993
75	37	7.4	1993
100	69	14	1996
150	89	19	1996

Views of the Board

Evidence submitted demonstrates that there is a very large resource base for heavy tertiary potential. It has been pointed out that only reasonably thick sands without bottom water can be considered amenable to thermal recovery because of heat loss considerations. Because of uncertainties about resource quality and appropriate recovery methods, it is imperative that field pilots be conducted, and these necessarily cause serious lags in obtaining significant supply from heavy tertiary sources. While acknowledging the aggressive reserves growth patterns of CPA, Dome, IPAC and, to some extent, Husky, the Board doubts, for the reasons noted above, that such rapid development can be achieved.

The Board concludes that commercial heavy tertiary development will require some 3 to 4 years of pilot testing, 2 to 3 years for design and implementation, and 1 to 3 years to obtain peak productivity response. The lag time to the start of the initial schemes is reflected in the Board's reserve growth pattern, Table 4-9. As tertiary experience is gained and real price improves the annual reserves growth is expected to increase so as to achieve two-thirds of the estimated 75 million m^3 tertiary potential within the forecast period.

It takes some time before productivity response occurs following commencement of thermal schemes. The CPA and IPAC normalized profiles in Figure 4-8 show that some ten years is required to reach peak productivity. The Board theorizes that heavy thermal tertiary recovery

TABLE 4-9 HEAVY TERTIARY RESERVES
GROWTH PATTERNS
millions of cubic metres per year

Year	CPA	Esso	IPAC[a]	Husky 7 Schemes	ERCB
1980	-	3	-	-	-
1981	-	4	-	-	-
1982	-	6	-	-	-
1983	47.0	4	-	2.8	-
1984	10.2	3	30	2.8	-
1985	3.2	4	30	-	1
1986	26.7	4	29		1
1987	26.7	2	-	7.0	2
1988	11.4	1	-	-	2
1989	2.9	-	-	-	3
1990	2.9	-	-	2.1	3
1991	10.5	-	-	-	4
1992	2.9	-	-	6.8	4
1993	2.9	-	-	-	4
1994	2.9	-	-	-	4
1995	2.9	-	-	-	4
1996	2.9	-	-	-	4
1997	2.9	-	-	-	4
1998	2.9	-	-	-	4
1999	2.9	-	-	-	4
	168	3	89	21	48

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[a] 150 $/m^3$ netback case

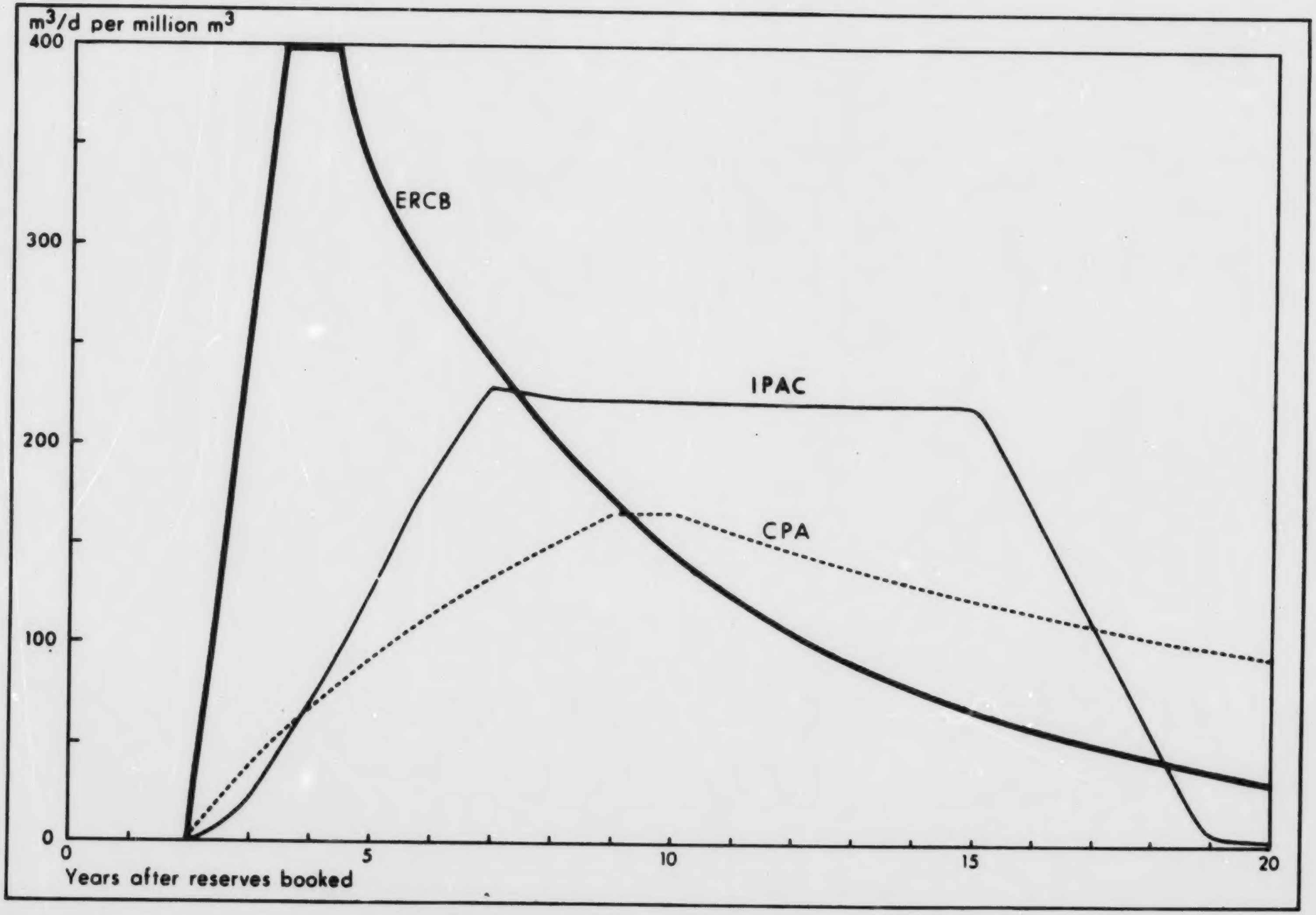

FIGURE 4-8 HEAVY OIL NORMALIZED PRODUCTIVITY PROFILES — TERTIARY
Comparison of submitted and ERCB profiles.

TABLE 4-10 HEAVY TERTIARY
PRODUCTIVE CAPACITY
thousands of cubic metres per day

Year	CPA	Esso	IPAC[a]	Dome		Husky[b]	ERCB
				SE Alta	Lloydminster[c]	7 Schemes	
1980	-	-	-		-		-
1981	-	1	-		-	*	-
1982	-	1	-		-	*	-
1983	*	1	-	*	1.2	*	-
1984	1	2	-	*	3.2	*	-
1985	2	3	-	*	5.6	1	-
1986	4	3	*	*	8.4	1	-
1987	7	4	2	*	10.7	1	*
1988	10	4	5	*	12.7	1	*
1989	12	4	8	1	13.9	2	1
1990	14	4	11	1	14.7	2	1
1991	17	4	13	1	15.0	2	2
1992	19	4	15	2	15.0	3	4
1993	20	4	17	2	15.3	3	5
1994	21	4	18	2	15.4	3	5
1995	22	4	19	2	15.4	3	6
1996	22	4	19	2	15.6	3	6
1997	23	3	19	2	15.8	3	7
1998	23	3	19	2	16.4	3	7
1999	22	3	17	2	16.4	3	8

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[a] 150 $\$/\text{m}^3$ netback case

[b] Includes pilot scheme productivity

[c] 115 $\$/\text{m}^3$ netback case

* Less than 1000 m^3/d

methods will necessarily use close well spacing and will therefore experience fairly rapid production response. For forecasting purposes the Board employed the normalized profile shown in Figure 4-8, which assumes a two-year build-up period to a peak rate of 400 m^3/d per million m^3 reserves.

Applying its theoretical productivity profile to the assumed reserves growth pattern results in the Board's capacity forecast shown in Table 4-10. While the Board has adopted this forecast for purposes of this report, it regards its own and the other forecasts as substantially conjectural. Also, it agrees with the opinion expressed by Husky that much more affirmative results from pilot testing and increased productive capacity will be required before installation of heavy oil upgrading plants can be seriously considered.

4.3 PENTANES PLUS - Productive Capacity of Remaining Established Reserves and Discoveries/Additions

Views of Participants

CPA, Dome, Esso, and Petro-Canada each submitted forecasts of the total Alberta productive capacity for pentanes plus over the 20-year period. The forecasts of production from established reserves (as of 31 December 1979) and production from discoveries/additions are shown in Tables 4-11 and 4-12, respectively. Chevron and Home submitted pentanes plus forecasts for the Kaybob South Beaverhill Lake Unit No. 3 and Carstairs gas plants respectively.

CPA's forecast of pentanes plus from currently connected and planned connections of established gas reserves was obtained by consulting operators of major gas plants. CPA's forecast of pentanes plus available from established gas reserves that are not expected to be connected in the near future and from new gas discoveries was based on a forecast of expected gas production from such sources and used a judgemental pentanes plus/gas ratio of 30 m^3 per million m^3 of gas reserves.

Dome's forecast of pentanes plus from currently committed gas reserves was developed mainly from the September 1978 report by the NEB, entitled "Canadian Oil Supply/Requirements". The forecast of pentanes plus from uncommitted and trend gas was based on Dome's own forecast of expected gas production from such sources and from an average pentanes plus/gas ratio of 66.49 m^3 per million m^3 as determined in a detailed study by the consulting firm, Kloepfer and Associates.

Esso's forecast of pentanes plus available from established reserves was based on its own plant-by-plant study. Its forecast of pentanes plus available from trend gas was based on a gas production forecast and its estimate of the composite pentanes plus/gas ratio of 50 m^3 million m^3.

Petro-Canada's forecasts of pentanes plus availability were based on a number of studies and reports made by the NEB, C. R. Winter and Associates, and others. The forecast of pentanes plus available from committed reserves was developed from forecasts for existing plants and from estimates, based on recent trends, for other committed but still shut-in reserves. Petro-Canada's forecasts of pentanes plus from uncommitted and trend reserves were made by using a pentanes plus/gas ratio of 67.8 m^3 per million m^3 as developed from an analysis of historical data by C. R. Winter and Associates.

None of the other participants at the hearing made submissions with respect to the productive capacity of pentanes plus.

Views of the Board

In its April 1978 report[1], the Board presented a forecast of pentanes plus production from both established and future gas reserves. This forecast was based on then current gas market expectations and regulatory policies. Some of these assumptions and projections are no longer reasonable. For this report, the Board has made an assessment of future pentanes plus availability based on its current forecast of gas production. The forecast reflects the following:

- The Board's recent increase in its estimate of the ultimate potential for gas from 3.1 trillion m^3 to 3.8 trillion m^3.
- The Board's recent revision of its gas supply protection formulae from a 30-year protection period to a 25-year protection period.
- Recently issued export licenses plus a nominal allowance for further export licenses which could be granted under the NEB's revised export licensing policy.
- A revised forecast of Canadian domestic gas requirements.

On the basis of its own studies and the information provided by the participants, the Board estimates that the pentanes plus/gas ratio for established reserves will decline from the 1979 level of 90 m^3 per million m^3 to 65 m^3 per million m^3 by 1991, and will thereafter remain approximately constant. As discussed earlier, the Board estimates that the pentanes plus/gas ratio for gas discoveries/additions will be some 65 m^3 per million m^3. The Board's pentanes plus discoveries/-additions reserves growth pattern is shown in Table 3-10.

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[1] Forecast of the Supply and Requirements of Crude Oil, Synthetic Crude Oil and Pentanes Plus in Alberta, 1978-1995. ERCB submission to the NEB, April 1978.

TABLE 4-11 PENTANES PLUS ESTABLISHED RESERVES
PRODUCTIVE CAPACITY
thousands of cubic metres per day

Year	CPA[a]	Dome	Esso	Petro-Canada	ERCB
1980	19.7	17.3	17	18.5	17
1981	19.1	16.2	17	17.4	18
1982	19.4	14.9	16	20.0	21
1983	17.5	13.6	16	18.6	20
1984	15.7	12.8	15	18.3	19
1985	13.9	11.6	14	16.8	17
1986	12.4	10.8	13	14.8	16
1987	11.4	9.7	11	13.0	14
1988	10.8	8.6	11	13.9	13
1989	10.0	7.7	10	11.5	11
1990	8.8	7.0	9	10.7	10
1991	7.8*	6.4	8	9.6	9
1992	6.9*	5.8	8	8.8	9
1993	5.9*	5.2	7	8.2	8
1994	5.0*	4.6	6	7.4	8
1995	4.0	4.3	5	6.6	8
1996	3.7*	3.9	5	5.8	8
1997	3.3*	3.6	5	5.5	8
1998	3.0*	3.3	4	5.0	7
1999	2.6*	3.0	4	4.3	7

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[a] Excludes some established but currently unconnected reserves

* Interpolated, CPA did not provide figures

TABLE 4-12 PENTANES PLUS DISCOVERIES/ADDITIONS
PRODUCTIVE CAPACITY
thousands of cubic metres per day

Year	CPA[a]	Dome	Esso	Petro-Canada	ERCB
1980	0.3	0.7	-	-	-
1981	0.7	2.4	-	-	-
1982	0.7	3.9	1	-	1
1983	1.0	4.2	1	3.1	2
1984	1.4	6.1	1	2.3	3
1985	1.4	6.8	2	4.1	3
1986	1.4	7.5	2	5.2	4
1987	1.4	8.1	3	5.1	4
1988	1.4	8.7	4	0.0	5
1989	1.4	9.7	4	2.4	5
1990	1.4	10.3	4	1.4	5
1991	1.7*	10.9	4	3.3	6
1992	2.0*	11.3	4	4.8	6
1993	2.2*	11.3	4	7.1	6
1994	2.5*	10.4	4	9.0	6
1995	2.8	11.6	5	11.1	6
1996	3.4*	12.4	5	12.1	6
1997	4.1*	13.2	5	11.9	7
1998	4.7*	14.1	5	11.5	7
1999	5.4*	13.5	5	10.9	7

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[a] Excludes some established but currently unconnected reserves
* Interpolated, CPA did not provide figures

The Board's forecasts of pentanes plus production from established reserves and production from discoveries/additions are shown in Tables 4-11 and 4-12 respectively. The Board forecasts the total pentanes plus production to increase from some 17 thousand m^3 per day in 1980 to a maximum of some 22 thousand m^3 per day in 1984, and to decline thereafter throughout the forecast period. The contribution to the total supply of crude oil and equivalent is shown in Figure 4-9.

4.4 BITUMEN SYNTHETIC CRUDE PRODUCTIVE CAPACITY

CPA, Esso, and Petro-Canada forecast the rate of bitumen synthetic crude development, assuming that economic circumstances would encourage operators to launch projects despite the technical and financial risks. Dome presented a lower production case, showing development under less favourable economic conditions, and compared this with much higher production patterns that could develop under economically attractive conditions. The forecasts of bitumen synthetic crude supply of each participant are shown in Table 4-13.

Views of CPA

CPA envisaged an aggressive development scenario and believed its forecast represented the upper limit of synthetic crude productive capacity. CPA foresaw Suncor expanding to 9 thousand m^3/d by 1982, and Syncrude expanding to 30 thousand m^3/d in 1989. Esso Cold Lake was forecast to have one train on stream in 1986 and to reach capacity in 1988. Alsands was forecast to reach capacity in 1989. Additional plants were forecast to come on production every two years in the 1990s adding 10 thousand m^3/d capacity every year beginning in 1992.

CPA also foresaw significant experimental activity, with bitumen production from field pilots increasing from the current level of 1600 m^3/d to some 20 700 m^3/d by 2000. CPA did not adjust the forecasts to reflect synthetic crude yield from raw bitumen. The bulk of the experimental bitumen production was expected to come from projects in the Cold Lake area. The forecast assumed no constraints from access to upgrading facilities, or other means of making the bitumen transportable and amenable to marketing. Included in the forecast was production from what was termed "small commercial schemes".

Views of Esso

Esso forecast the pace of bitumen synthetic crude development, keeping in mind manpower availability and manufacturing capacity constraints and assuming that suitable fiscal terms would be in place. Esso believed that if bitumen synthetic development became a national priority, production could be increased to even higher rates. The forecast shown in Table 4-13 assumes Suncor expanding to 9 thousand m^3 in 1982, and Syncrude to 30 thousand m^3/d in 1988. Alsands and Esso Cold Lake were each forecast to reach full capacity of 22 thousand m^3/d in 1988. Additional bitumen synthetic crude plants would come on stream every other year, starting in 1993, and then would add 11 thousand m^3/d capacity annually. Production in the year 2000 would be 171 thousand m^3/d of synthetic crude oil.

Bitumen production from experimental projects was forecast to increase to 5 thousand m^3/d by the mid-1980s and to remain at that level throughout the remainder of the forecast.

Views of Dome

Dome presented high (optimistic) and low (pessimistic) development cases shown in Table 4-13, with the difference between the two stemming from economic attractiveness. Manpower and material availability were assumed not to be constraints.

For the high (optimistic) case, in which synthetic crude prices were assumed to escalate so as to generate 12-14 per cent real DCF rates of return, Dome forecast a Syncrude expansion in 1985-86, with a further expansion to double capacity to 50 thousand m^3/d by the year 2000. Suncor was assumed to secure additional sources of bitumen feed and to continue production through to the year 2000. Esso Cold Lake and Alsands were assumed to come on stream in 1987 and reach full production capacity of 24 thousand m^3/d by 1993 and 1994, respectively. Both plants were forecast to add one more train and reach a capacity of 36 thousand m^3/d by the end of the forecast period. Two additional bitumen synthetic crude plants were forecast to come on stream in each of 1991 and 1994, and one plant in each of 1993, 1998, and 2000. Production in the year 2000 would then reach 316 thousand m^3/d.

The lower (pessimistic) case reflected current uncertainty respecting synthetic crude prices and the lack of government commitment to developing bitumen deposits. The forecast assumed Suncor would expand to 9 thousand m^3/d in 1982, and would cease operations when plant feed from the existing mine pit runs out in 1998. Syncrude was forecast to add one train in the late 1990s. Esso Cold Lake and Alsands were forecast to come on stream in 1987 and 1988, respectively. Dome suggested that one further mining project, to start production in 1990, could be the last to use current hot water extraction and fluid coking technology. However, for this case it assumed that a second large in situ project would be on stream in 1993. Bitumen synthetic crude production was thereby forecast to reach 129 thousand m^3/d by the year 2000 for the low case.

Views of Petro-Canada

The Petro-Canada forecast assumed that satisfactory pricing agreements would be forthcoming and that project scheduling would be optimized with regard to manpower and manufacturing capability. Petro-Canada indicated that finds of offshore oil as well as relative pricing of oil from various sources could affect the rate of bitumen synthetic crude development. Suncor was forecast to reach 9 thousand m^3/d in 1982, with Syncrude expanding to 29.4 thousand m^3/d in 1989. Petro-Canada assumed that its announced joint venture plant would come on stream in 1990 and reach full production of 24 thousand m^3/d in 1994. An additional mining operation was forecast to come on stream in 1997. Esso Cold Lake was forecast to come on stream in 1987, with two more in situ plants commencing operations in 1994 and 1999.

Production from experimental schemes was forecast to increase from the present level of 2 thousand m^3/d to 5 thousand m^3/d by 1985. Production would remain constant thereafter with new experimental schemes merely replacing declining production from older or abandoned schemes.

Views of the Board

The Board observes that the outlook for bitumen synthetic crude supply is markedly affected by at least three key factors:

- The economic outlook respecting synthetic crude price netback.
- Current status of, and future developments in, technology that may affect efficiency and environmental acceptability of developments.
- Infrastructure requirements and social impact matters that may limit the potential pace of development.

The Board agrees with the industry concensus that bitumen synthetic crude is potentially the principal source of replenishment supply and is capable of off-setting the now rapid decline in conventional crude production. The Board therefore believes it is reasonable to assume that a favourable netback to developers will be ensured to encourage not only additional commercial projects, but also research and development of more efficient and environmentally acceptable technology.

TABLE 4-13 COMPARISON - BITUMEN SYNTHETIC COMMERCIAL AND EXPERIMENTAL PRODUCTIVE CAPACITY
thousands of cubic metres per day

Year	CPA		Esso		Dome		Petro-Canada		ERCB	
	Commercial	Experimental	Commercial	Experimental	Optimistic	Pessimistic	Commercial	Experimental	Commercial	Experimental
1980	18	2	17	2	21	21	19	2	21	2
1981	20	3	20	3	26	26	23	2	23	3
1982	26	3	26	3	28	28	26	2	26	5
1983	29	3	28	4	29	29	27	2	29	6
1984	29	4	29	4	30	30	30	2	29	7
1985	29	6	29	5	32	32	32	2	29	7
1986	30	8	31	5	39	33	31	3	29	7
1987	51	9	49	5	46	36	37	3	41	7
1988	76	10	76	5	62	44	55	3	57	7
1989	83	11	83	5	79	59	70	3	72	7
1990	83	13	83	5	90	75	82	4	81	7
1991		14	83	5	102	85	96	4	89	7
1992		14	83	5	115	95	99	4	97	7
1993		15	94	5	136	104	104	4	105	7
1994		15	105	5	160	110	113	4	113	7
1995	125	16	116	5	185	123	125	4	121	7
1996		16	127	5	222	133	132	4	129	7
1997		18	138	5	242	136	141	4	137	7
1998		18	149	5	253	129	151	4	145	7
1999		19	160	5	264	129	156	4	153	7
2000	173	21	171	5	316	129	167	4	161	7

TABLE 4-14 BITUMEN SYNTHETIC ERCB GROWTH FORECAST - COMMERCIAL
thousands of cubic metres per day

Year	Suncor	Syncrude	Alsands	Esso	New Projects	Total
1980	7	14	-	-	-	21
1981	7	16	-	-	-	23
1982	9	17	-	-	-	26
1983	9	20	-	-	-	29
1984	9	20	-	-	-	29
1985	9	20	-	-	-	29
1986	9	20	-	-	-	29
1987	9	20	6	6	-	41
1988	9	20	14	14	-	57
1989	9	25	19	19	-	72
1990	9	29	21	22	-	81
1991	9	29	21	22	8	89
1992	9	29	21	22	16	97
1993	9	29	21	22	24	105
1994	9	29	21	22	32	113
1995	9	29	21	22	40	121
1996	9	29	21	22	48	129
1997	9	29	21	22	56	137
1998	9	29	21	22	64	145
1999	9	29	21	22	72	153
2000	9	29	21	22	80	161

The Board believes that current commercial mining programs and the progress indicated by the applied-for Esso Cold Lake in situ project demonstrate that primary generation technology is available for both mining and in situ recovery of bitumen.

As improved mining extraction technology - a necessity for improved resource recovery and environmental/reclamation acceptability - is developed, mining-type operations will enter a significant second generation. Similarly, much better in situ recovery methods than proposed for the initial production operations at Esso Cold Lake would have to be developed in order for in situ production to reach its projected dominant position in the synthetic crude supply picture. The Board agrees with industry observations, particularly those outlined in the Dome submission, that technology demonstration and improvement is an arduous task, and that it may take a decade or more of sustained experimentation to develop second generation methods. In contrast, upgrading techniques are advancing rapidly and can be expected to meet resource utilization efficiency and environmental standards without necessitating delays in programs.

Industry participants generally foresaw infrastructure and social impact, including skilled labour supply, as imposing some limits on the rate of development. However, the Board believes these constraints would be surmountable if firm fiscal commitments are made and appropriate advance planning occurs in a timely manner.

Taking all factors into consideration, the Board forecasts that synthetic crude production will expand in the pattern shown in Table 4-14 to reach a level of 81 thousand m^3/d by 1990. Delays of a year or more in the Alsands, or Esso Cold Lake projects, however, would obviously lower this target by 10 thousand m^3/d or greater.

When projecting synthetic crude producing capacity during the 1990s, the Board believes that various delays that tend to accumulate must be considered in addition to constraints that may be imposed by shortages of skilled manpower, manufacturer scheduling and infrastructure considerations. These, as illustrated in the Dome submission, include time allotments for pilot or field demonstration testing, conceptual design of commercial projects, and regulatory and government reviews, before construction, commissioning and start-up.

This cumulative effect requires that for plants to go on stream as projected during the 1990s, approvals be issued and construction launched during the next five to eight years. The Board, in concert with the views expressed by most participants, considers this an achievable, though aggressive, development target. However, it considers the Dome high case to be unachievable. In summary, the Board's own projections show synthetic crude production growing from a level of 81 thousand m^3/d in 1990 to a level of 161 thousand m^3/d by the year 2000. However, the Board would consider the Dome low case, Table 4-13, as a more likely pattern if applications for a number of new commercial projects did not materialize in the next four to eight years.

4.5 Summary - Productive Capacity

The ERCB productive capacity forecasts of Alberta crude oil and equivalent from all sources for the 20-year forecast period are summarized in Table 4-15. The tabulated forecast is also presented in graphic form, along with actual production for each crude oil source for the past 10 years, in Figure 4-9.

While the submitted and Board productive capacity forecasts have been presented in tabular form, it is also worthwhile to provide some graphic comparisons. The productive capacity forecasts for discoveries/additions of light-medium, heavy and pentanes plus have therefore been summarized in Figure 4-10. Because of the considerable variation in forecasts and the importance of analysing light-medium tertiary and heavy tertiary productive capacity separately, two graphs, Figure 4-11 and 4-12 respectively, are presented. Figure 4-13 shows the forecasts of bitumen synthetic production. No graphic comparison of the productive capacity attributed to established reserves is presented because, as can be seen from the tabulated forecasts, the variations are small. Figure 4-14 provides a comparison of the total productive capacity of Alberta crude oil and equivalent.

TABLE 4-15 ERCB PRODUCTIVE CAPACITY OF ALBERTA CRUDE OIL AND EQUIVALENT - All Sources
thousands of cubic metres per day

Year	Light-Medium	Pentanes Plus	Heavy	Synthetic[a]	Total
1980	166	17	14	23	220
1981	161	18	13	26	218
1982	149	22	12	31	214
1983	139	22	12	35	208
1984	127	22	11	36	196
1985	120	20	11	36	187
1986	112	20	10	36	178
1987	107	18	10	48	183
1988	99	18	10	65	191
1989	96	16	10	79	201
1990	91	15	10	88	204
1991	87	15	10	96	208
1992	83	15	12	104	214
1993	81	14	11	112	218
1994	77	14	11	120	222
1995	75	14	12	128	229
1996	73	14	11	136	234
1997	72	14	12	144	242
1998	70	14	12	152	248
1999	69	14	12	160	255

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[a] Includes experimental schemes - heavy crude oil and bitumen

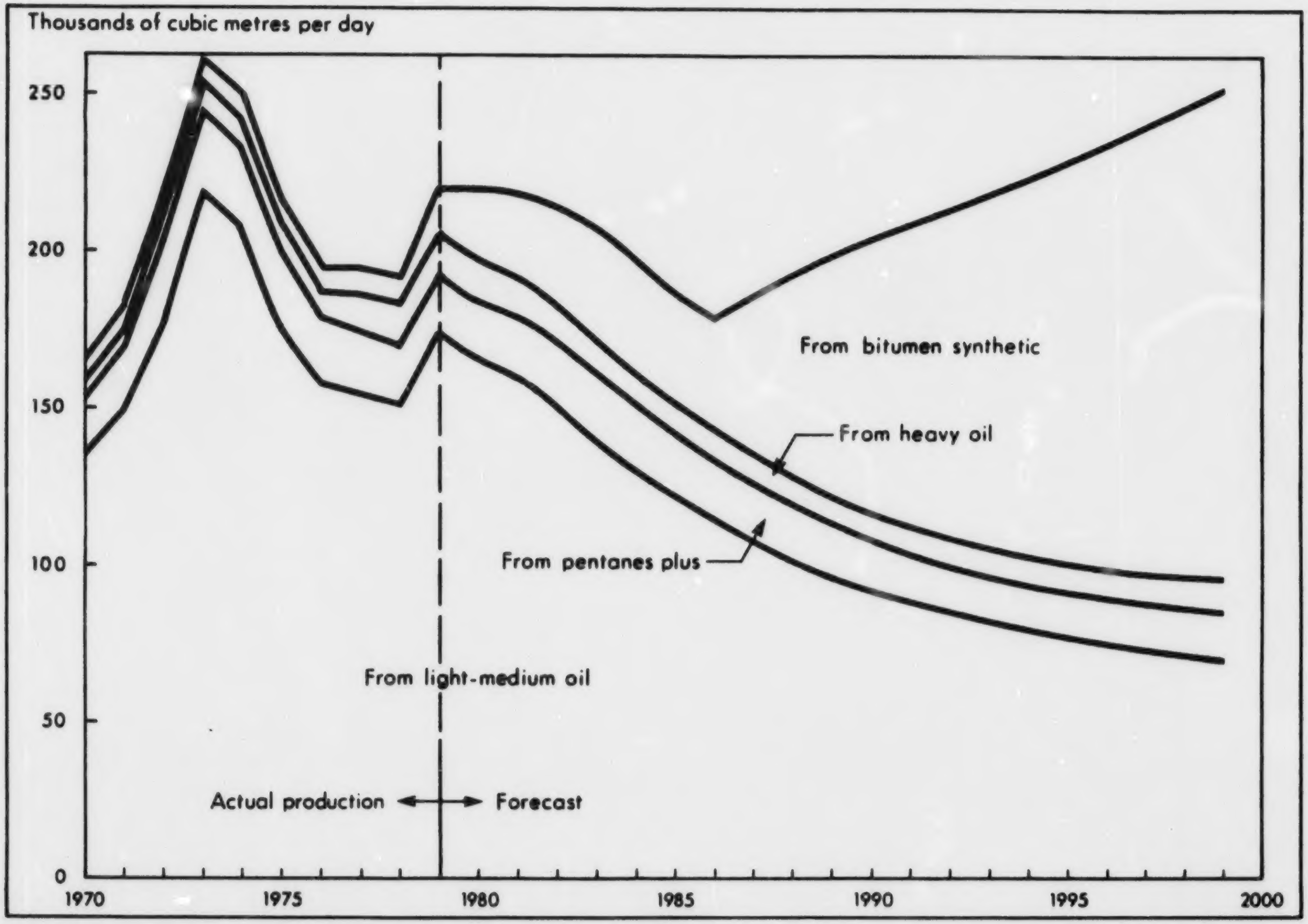

FIGURE 4-9 ERCB PRODUCTIVE CAPACITY OF ALBERTA'S CRUDE OIL AND EQUIVALENT. All sources.

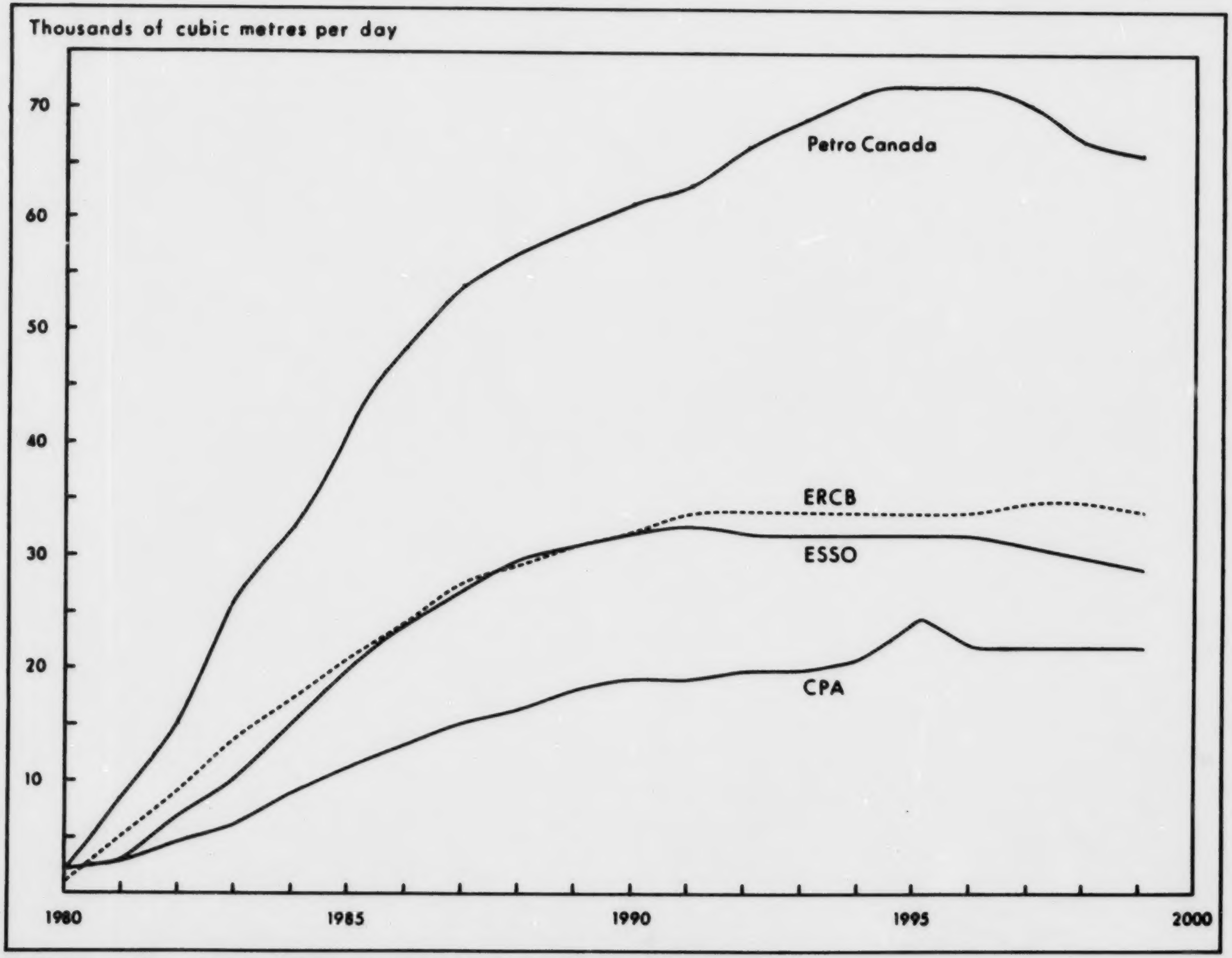

FIGURE 4-10 LIGHT-MEDIUM, HEAVY OIL AND PENTANES PLUS PRODUCTIVE CAPACITY - DISCOVERIES/ADDITIONS
Comparison of submitted and ERCB forecasts

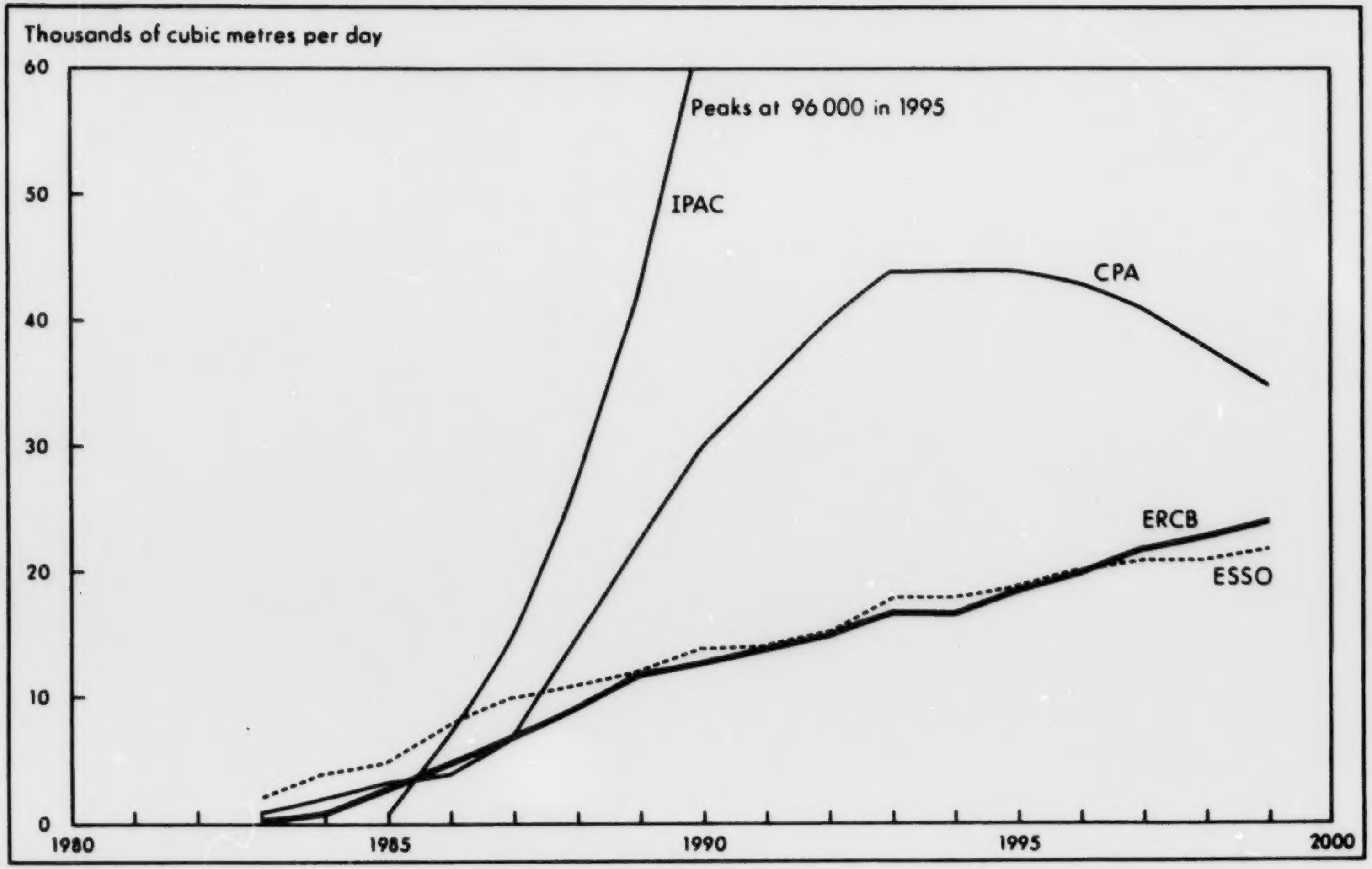

FIGURE 4-11 LIGHT-MEDIUM PRODUCTIVE CAPACITY — TERTIARY
Comparison of submitted and ERCB forecasts.

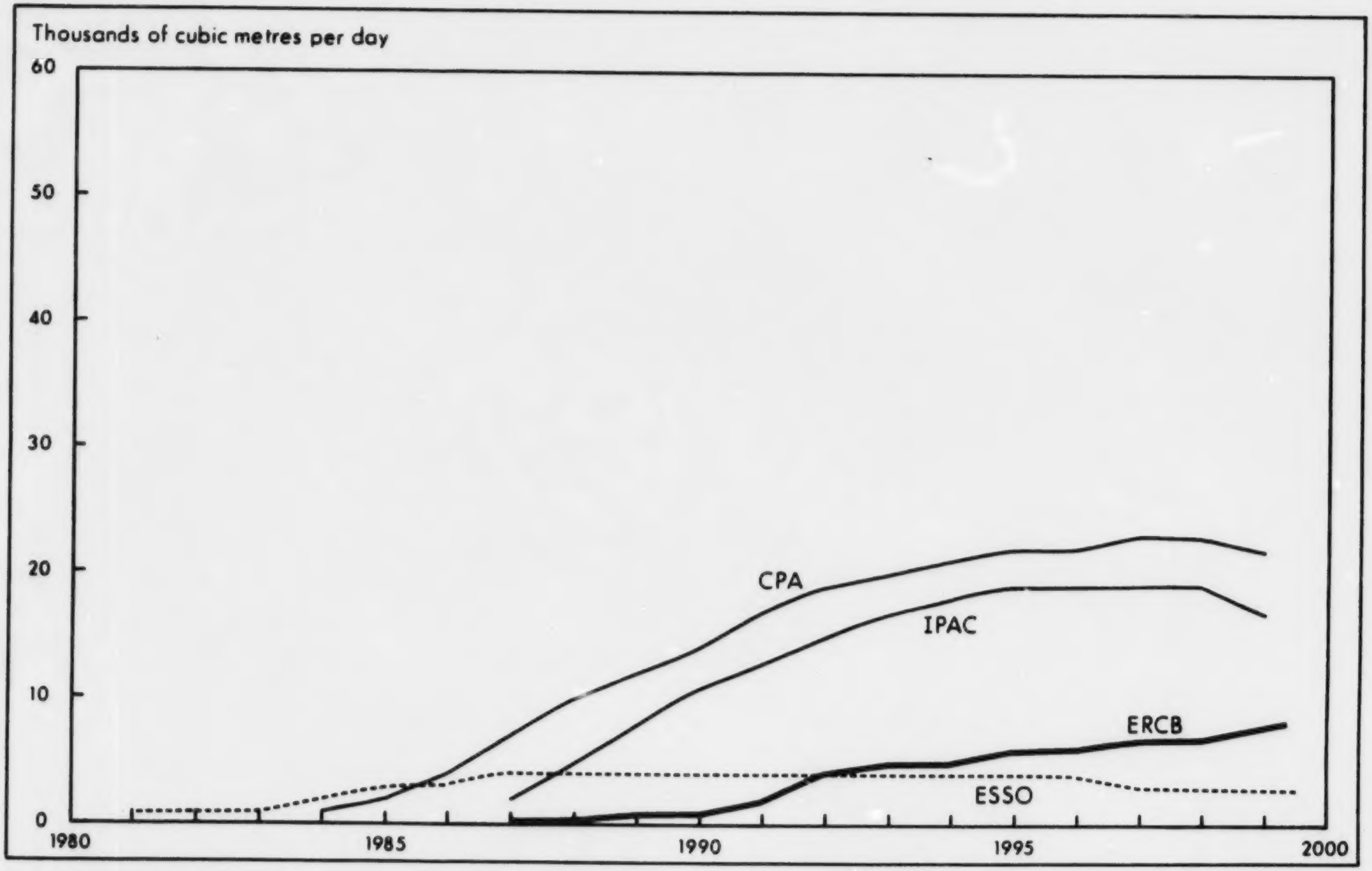

FIGURE 4-12 HEAVY OIL PRODUCTIVE CAPACITY — TERTIARY

Comparison of submitted and ERCB forecasts.

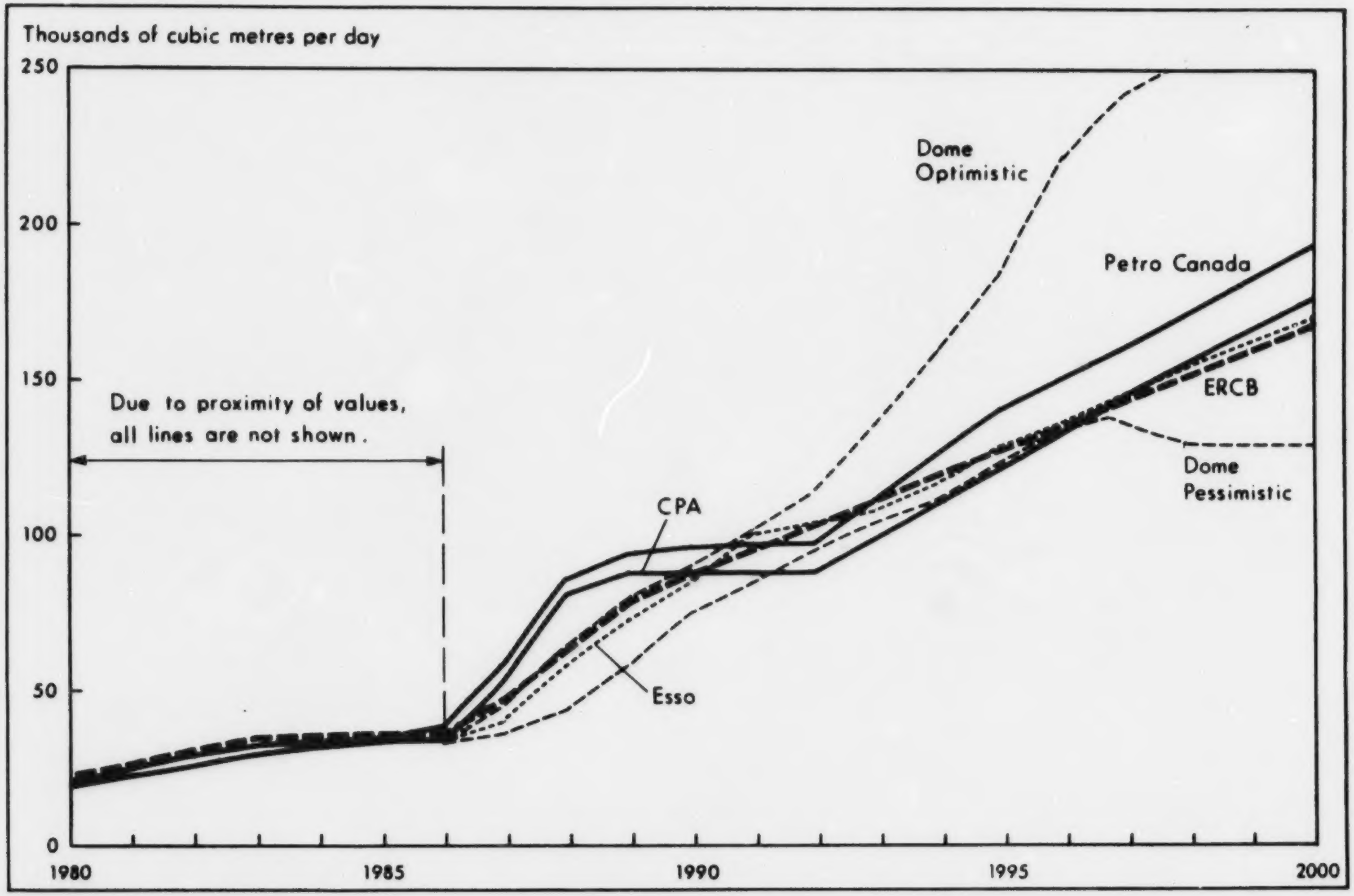

FIGURE 4-13 BITUMEN SYNTHETIC COMMERCIAL PLUS EXPERIMENTAL PRODUCTIVE CAPACITY
Comparison of submitted and ERCB forecasts.

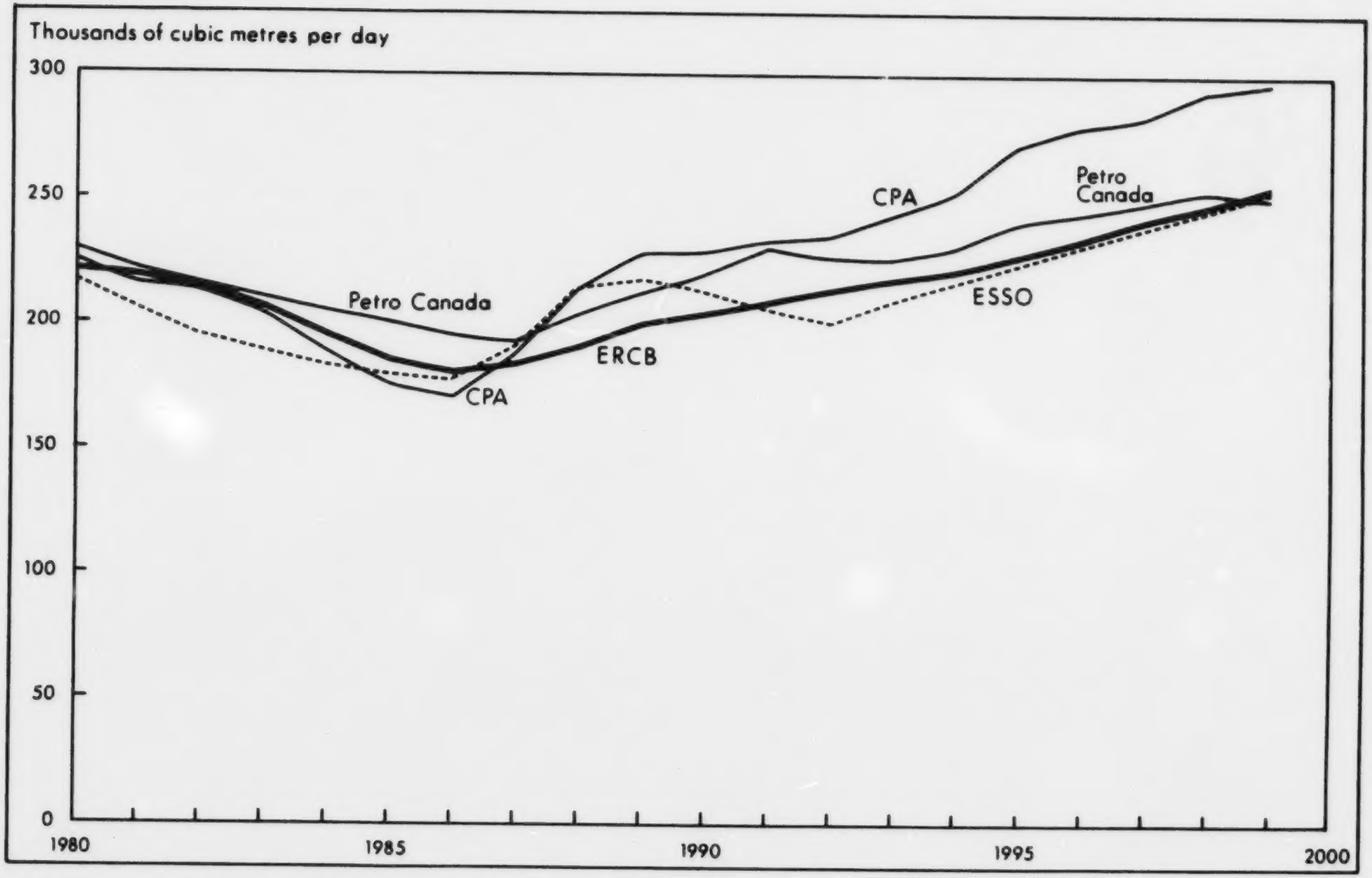

FIGURE 4-14 TOTAL PRODUCTIVE CAPACITY OF ALBERTA'S CRUDE OIL AND EQUIVALENT. All sources. Comparison of submitted and ERCB forecasts.

5 FACTORS AFFECTING NEAR TERM AND LONGER TERM SUPPLY OF CRUDE OIL AND EQUIVALENT

In addressing the potential for supplementing oil supplies, several submissions contained information respecting infill drilling for conventional oil production, the intensified infill drilling that might accompany tertiary operations, the impact of increased production costs as reservoirs reach a more advanced stage of depletion, and the effects of lead time on supply replenishment from tertiary and synthetic projects.

5.1 INFILL DRILLING FOR CONVENTIONAL PRODUCTION

Views of the Participants

The CPA survey of companies determined that infill drilling might occur:

- To prevent migration of reserves from company owned lands
- To increase ultimate recovery, such as in a very low permeability and/or a highly stratified reservoir
- To facilitate a tertiary recovery scheme

The survey indicated that most companies believed that the effect of infill drilling on the ultimate potential would be marginal for most pools. CPA further concluded that accelerating production via infill drilling would not materially increase the near term oil supply.

Chevron commented that it could not see any economic incentive for infill drilling beyond that necessary to meet productivity forecasts. Such drilling would only modestly accelerate rates of depletion of pools that are already in decline, and result in little or no improved recovery. It referred to programs in three comparatively large reservoirs to illustrate circumstances where a few infill wells would likely be drilled.

For southeastern Alberta, where oil fields contain crude oil of light-medium and heavy gravity, Dome concluded that water coning was a common constraint to oil recovery. Given appropriate economic incentives, Dome believed that several hundred infill wells could be justified and would result in a supplemental oil supply of about 2 thousand m^3/d initially and decline to one-sixth of the initial level over a ten-year period. For the Lloydminster heavy oil area, Dome assumed some 1.3 billion m^3 of in-place oil reserves that could be developed on 8-hectare well spacing over a 20-year development period. Dome considered producer netback to be decisive for the pace of development and estimated the impact as follows:

Netback $/$m^3$	Infill Wells per year	Incremental Production thousand m^3/d)
64.19	80	2.4
114.63	680	10 to 12 primary plus 10 waterflood

Esso submitted that special incentives for infill drilling over and above those infill wells currently considered economic would not contribute significantly to the province's long term supply. It added that reserves additions from infill drilling in Alberta's established pools would be modest. Further, while productivity would be increased in the near term, the gains would be short-lived and production increases would be soon offset by more rapid declines. These reasons, coupled with the high costs of drilling and production facilities, led Esso to conclude that accelerated infill drilling in established fields is less attractive than developing other sources of supply.

IPAC based its estimates of the potential for additional supplies through accelerated infill drilling on a review of 21 light-medium and 11 heavy crude pools for which current productivity is approximately 110 thousand m^3/d. By increasing producer netback from a base case of 50 \$/m^3 to levels of 75 to 100 \$/m^3, a total of 1600 infill wells could be justified. The result would be a maximum supplemental supply of approximately 10 thousand m^3/d by 1984, falling to zero by 1989 and becoming negative thereafter owing to the accelerated depletion.

Views of the Board

Most evidence points to the conclusion that accelerating the depletion process through infill drilling, particularly in the light-medium pools, does not have practical merit, as only marginal supplementary production capacity would result and this would soon be offset by lower rates of production a few years later. However, if producer netbacks for conventional oil production were to be increased to 100 \$/m^3, considerable drilling activity, both infill and close offset, might develop in the relatively shallow, lower cost drilling regions in the eastern portion of the province. If this occurred, as many as a thousand additional wells might be drilled in these regions and lead to sustained supplemental supplies of perhaps 3 or 4 thousand m^3/d. Such drilling would be mainly development drilling of pools which previously were uneconomic to develop. The Board believes that such extensive drilling in the Lloydminster heavy oil area would be fostered by prospects for new supplies from tertiary operations rather than for marginal conventional production.

5.2 DRILLING FOR TERTIARY OPERATIONS

Views of Participants

CPA reviewed 23 light-medium pools and 11 heavy oil pools which appeared amenable to tertiary recovery programs. It forecast 720 infill wells in light-medium reservoirs would be drilled from 1984 to 1992, resulting in incremental peak production of 44 thousand m^3/d in the mid-1990s, with a gradual decline thereafter. Most of these developments would occur in the Beaverhill Lake oil pools. For heavy tertiary production, it projected drilling 4030 more wells, about triple the current number of producers, resulting in peak production of 18 thousand m^3/d in 1994.

Dome examined the potential and economic sensitivity of tertiary recovery from Cretaceous and Triassic sands in four areas. Its conclusions are summarized as follows:

Area	Approximate Additional Wells	Added Oil Supply	Required Netback
		thousand m^3	$/$m^3$ 1978
Southeastern Alberta	600	2	140
Pembina Cardium	10 000	20	80
Deep Basin Cardium & Dunvegan	17 000	8	250
Lloydminster	21 000	20	120

The Dome studies did not take into account such potential problems as equipment and manpower availability that might develop in the multi-billion dollar ventures contemplated. Also, the studies were not sufficiently detailed to eliminate projects from which net energy recovery might be less than energy consumed in the recovery program.

Husky confined its estimates to seven projects in the Lloydminster area where it estimated that infill drilling on 8-hectare spacing, equivalent to possibly 1000 wells, could yield about 3 thousand m^3/d of supplemental oil supply.

Esso and Petro-Canada anticipated additional drilling for heavy oil tertiary programs, but did not provide specific estimates.

The IPAC forecast of tertiary recovery potential for heavy oil pools identified infill drilling as an inherent requirement of such programs. At a netback of 100 $\$/m^3$ IPAC forecast tertiary production beginning in 1986, rising to a plateau of about 13 thousand m^3/d by 1992 and declining thereafter. About 2500 additional wells would be required.

Views of the Board

It appears that the light-medium tertiary potential of the Beaverhill Lake, Gilwood and other Devonian pools can be developed with possibly only 1000 additional wells. The Board considers Dome's estimates of light-medium potential from Pembina and the deep basin sands as mainly illustrating economic sensitivity; neither would appear to be technically viable at this time.

To exploit the tertiary potential of the shallow heavy oil accumulations in the eastern region of the province will require much additional drilling. Ultimate potential and the ensuing drilling requirements will relate closely to the degree of production success obtained from field pilot tests. With the limited pace of tertiary heavy oil development it expects, the Board has assumed that 3000 wells eventually may be needed. But in view of the very limited evidence, the Board regards its own, as well as other, estimates of well drilling requirements for tertiary heavy oil production as conjectural.

5.3 COSTS OF PRODUCTION

Views of Participants

CPA stated that as well producing rates decline, operating costs per unit of oil production increase rapidly even if per well operating costs remain constant. As water/oil ratios increase over time, the cost of lifting, processing and reinjecting more water will increase the cost of producing conventional oil reserves. CPA estimated that average industry operating costs had increased from 2.17 $\$/m^3$ in 1970 to 10.37 $\$/m^3$ in 1979 for an average annual rate of increase of 19 per cent. CPA projected future costs to increase at 2 per cent per annum in real terms reaching 86 $\$/m^3$ by 1990.

Esso forecast unit production costs to escalate faster than inflation as the productivity of established oil fields declines. Additional investments to expand water handling facilities, install artificial lift, and replace equipment would be required. The major contributor to increased operating costs would be increasing water/oil ratios and the increased operational attention needed to maintain operating efficiency. With operating costs increasing and productivity decreasing, unit costs would rise rapidly. Esso presented the results of a study of Redwater and Judy Creek fields to determine relationships between producer net revenue, future costs of production and supply from established reserves. The study showed that if future net revenue per cubic metre of oil remained constant, large sectors of the pools would become uneconomic within the next five to ten years.

Home submitted the following estimates for Swan Hills Unit No. 1:

	1977	1980
	\$/m³	\$/m³
Operating Costs	1.82	4.84
Royalties and Taxes	48.64	73.88
Crude Oil Prices	63	94.52
Producer Netback	12.59	15.80

The producer netback had increased at only 6.7 per cent/annum while GNP inflation during the same period was about 7.8 per cent/annum. If this trend were to continue, industry capability to generate reinvestment funds from these operations for tertiary programs and other developments would diminish rather than expand in the manner believed necessary.

Cost estimates for tertiary recovery in the IPAC submission indicate that capital recovery costs will be 10 to 30 $\$/m^3$, whereas operating costs might take up 40 to 80 $\$/m^3$ depending upon the rate of incremental production response and the costs of equipment and materials. Dome's estimates appear to indicate similar results.

Views of the Board

A major share of the oil production in the province derives from reservoirs discovered before 1965. The decline in productive capacity of these reservoirs is a natural progression which can now be forecast quite accurately. The Board agrees with industry that for these reservoirs, now typically in the latter third of their producing lives, fairly rapid escalation of costs for lifting and treating water production will have to be borne. The Board concludes that the weighted average operating costs for these pools, in 1980 dollars, will be 60 to 80 $\$/m^3$ of oil produced over the next decade.

For tertiary operations in the more attractive light-medium prospects capital and operating costs may be fairly low. However, for many heavy oil projects and the lower permeability light-medium reservoirs, the combined costs could run beyond 100 $\$/m^3$ of productivity.

5.4 THE EFFECT OF LEAD TIMES ON SUPPLY REPLENISHMENT FROM NON-CONVENTIONAL SOURCES

Conventional supplies of crude oil and equivalent from fields in Alberta are declining and will continue declining even in the face of active exploration and development drilling. The Board's forecast, shown on Figure 1-2, indicates that, on an annual basis, conventional supply will fall by about 10 thousand m^3/d for each year in the period 1980 - 1989, and by 4 thousand m^3 in each year thereafter.

To offset these declines, tertiary production and synthetic crude projects could be installed. Evidence generally indicates that, in terms of 1980 dollars, capital investment requirements for these sources would fall in the range 200 to 300 thousand $\$/m^3/d$, so that to obtain 10 thousand m^3/d non-conventional supply would require capital investment of 2 to 3 billion dollars plus large amounts of manpower and equipment.

Decisions to proceed with non-conventional projects, which often require large front-end capital and involve technical risk, are based on careful consideration of the prospects for satisfactory economic return. If the prospects are uncertain, programs may not proceed beyond a conceptual stage. In any case, full assembly of capital and manpower occurs only after a firm decision to commit to the program has been made. Delays in decisions, whether the result of government policy uncertainties, regulations respecting resource or environmental conservation, or from consideration of socio-economic matters, tend to set back the date when a program is firmly committed. The lead time to accommodate these considerations may be as little as six months but may extend over three or four years and even more for very large projects. This delay, to a great extent in the hands of regulatory agencies and governments, conceivably could be shortened if required in an emergency situation.

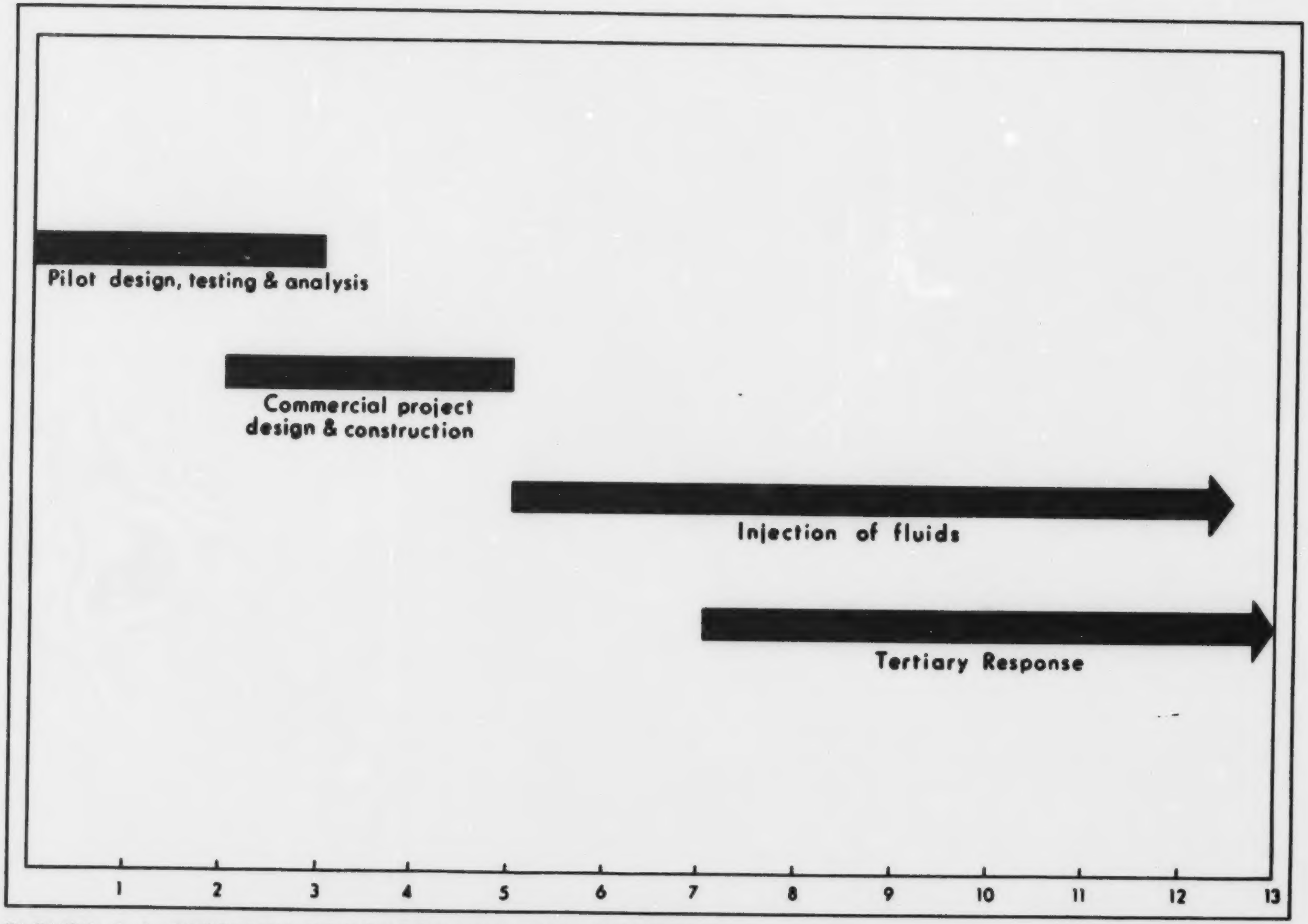

FIGURE 5-1 TERTIARY RECOVERY PROJECT SCHEDULE
Copied from IPAC submission - figure 4

In forecasting the growth of non-conventional supplies, allowance must also be made for the time required for pilot or demonstration plant design and testing, commercial project design and construction, and the period from plant start-up to full scale production. The typical lead time required for these activities is illustrated in Figures 5-1 and 5-2, taken from the IPAC and Dome submissions respectively. This period may be collectively called the concept-to-production lead time. Evidence broadly available to the Board indicates that the following allowances should be made for concept-to-production lead time:

SOURCE	CONCEPT-TO-PRODUCTION LEAD TIME
light-medium tertiary	3 - 6 years
heavy tertiary	5 - 10 years
bitumen synthetic - in situ	10 - 15 years
bitumen synthetic - surface	7 - 10 years
(coal synthetic might be 10 - 20 years)	

In light of these lead times, even assuming a favourable economic climate, a rapid regulatory review process, and an aggressive development scenario, only a very small amount of non-conventional oil supply could be brought on stream in the next five years. With the continuing decline in conventional production, a drop in overall supply of roughly 50 thousand m^3/d, or about one-quarter of current capacity, is therefore highly likely by 1985.

If construction of the Esso Cold Lake and Alsands projects were launched today, the downward trend in overall supply could be reversed in the latter part of the decade by the addition of some 45 thousand m^3/d of synthetic crude. Delays in commencing construction of those projects, on the other hand, would automatically lead to further slippage in overall supply. For the tertiary oil sources, while the forecasts adopted by the Board assume fairly active development, any reasonable allowance for the lead time from concept-to-production confirms that the tertiary oil is not likely to be a significant source of supply replenishment for another seven to ten years.

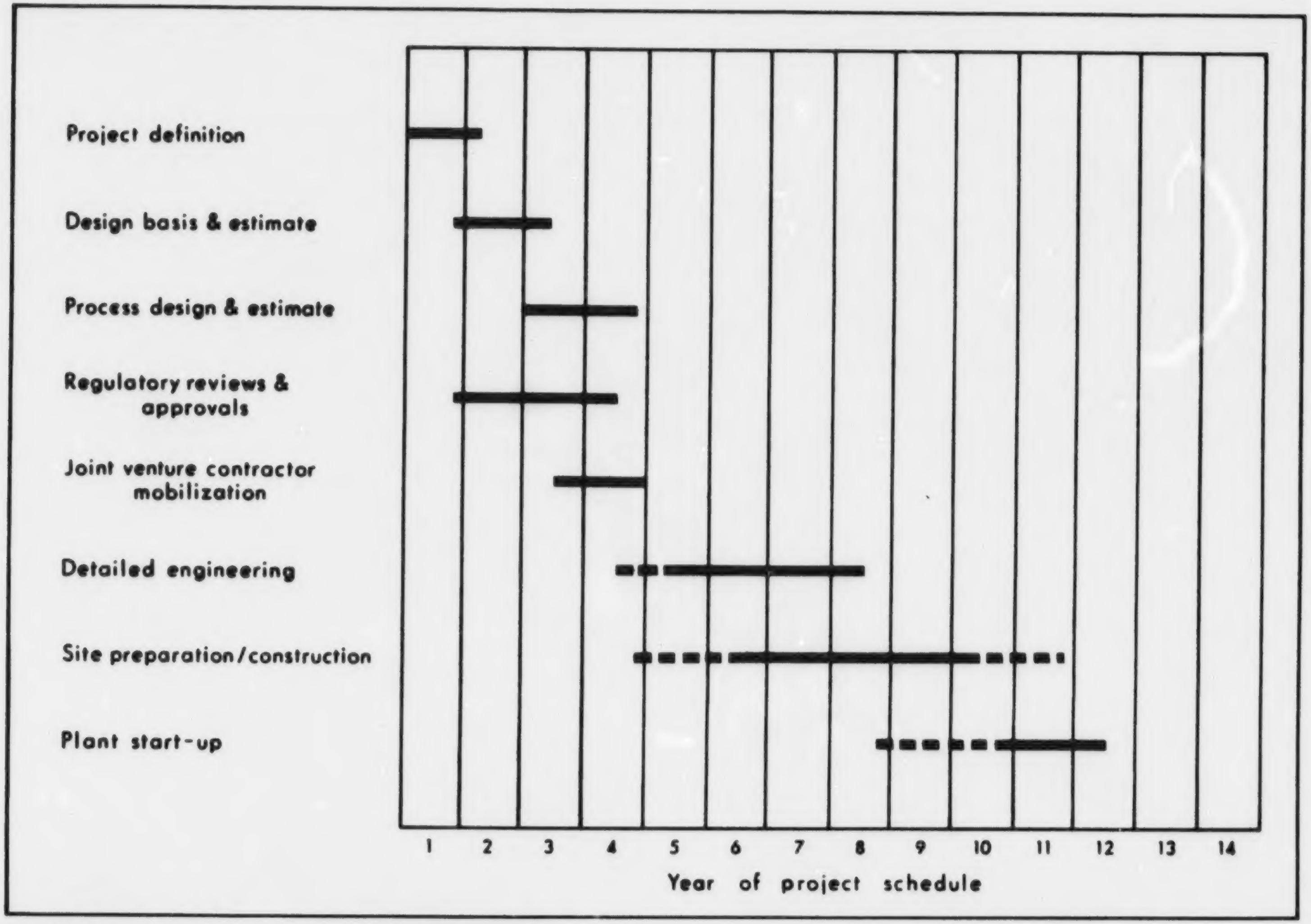

FIGURE 5-2 ESSO COLD LAKE PROJECT

In summary, the following conclusions apply respecting supply replenishment from non-conventional sources:

- Regulatory decisions may delay programs by six months to three or four years.
- Programs likely would not proceed beyond the pilot stage if long range economic policies are uncertain.
- A lead time of a few years to a decade or more is required from pilot concept to full production for many projects. Only an emergency program, such as might be undertaken as a strategic measure, with some government guarantees of construction capital loans or other similar support could shorten this period.
- Development of several tertiary and bitumen synthetic projects would have to be launched in the near future in order to replenish declining conventional supplies and fulfill the ERCB projections of overall supply. Other alternatives such as direct coal liquefaction might also be capable of providing some supplemental supplies in the latter half of the forecast period.

APPENDIX A-1

ENERGY RESOURCES CONSERVATION BOARD

PROCEEDING NO. 800065

NOTICE OF HEARING

FORECAST PRODUCTIVE CAPACITY AND ULTIMATE POTENTIAL OF CRUDE OIL AND PENTANES PLUS

TAKE NOTICE that the Energy Resources Conservation Board will hold a public hearing at the Court House, 611 - 4 Street S.W., Calgary, Alberta, on Tuesday, 24 June 1980, at the hour of 9:00 a.m., for the purpose of inquiring into and hearing representations respecting the forecast Alberta productive capacity of crude oil and pentanes plus. The capacity forecasts for the period 1980 to 2000 inclusive should be categorized with respect to light and medium conventional oil, heavy conventional oil and synthetic oil and should include capacity estimates from established reserves, future additions to reserves due to new drilling and from enhanced recovery applied to established and future reserves. The Board also intends to inquire into Alberta's ultimate potential of crude oil and pentanes plus.

AND FURTHER TAKE NOTICE that the Board will make available an Informational Letter outlining in more detail the scope of the hearing. The Informational Letter (IL 80-3) is available from the offices of the Board, 603 - 6 Avenue S.W., Calgary, Alberta, T2P 0T4.

Any person wishing to make a submission with respect to this proceeding shall file on or before 30 May 1980, fifteen copies of his submission with the undersigned at the Board's address set out below.

A copy of each submission filed in respect of the proceeding and a list of submittors will be available for inspection at the Board's Records Centre after 2 June 1980. Submittors may then obtain copies of submissions from other participants.

DATED at Calgary, Alberta on 8 February 1980.

ENERGY RESOURCES CONSERVATION BOARD

A. L. McLarty
Board Solicitor

APPENDIX A-2

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

Informational Letter
IL 80-3

TO: All Operators

SUBMISSIONS TO PROCEEDING 800065
PRODUCTIVE CAPACITY AND ULTIMATE POTENTIAL OF CRUDE OIL AND PENTANES PLUS

In light of the prevailing supply/demand balance of Alberta oil, the Board has scheduled a public hearing for 24 June 1980 to review the future crude oil productive capacity and ultimate potential from all sources in Alberta. The Board invites interested parties to file submissions by 30 May 1980. Further details respecting the time and place of the hearing and for the filing of submissions, are available in the Notice of Hearing.

The Board requests the submittors to address matters relating to productive capacity and ultimate potential of each of: light and medium conventional crude oil, heavy conventional crude oil, and pentanes plus. In addition, submissions are requested respecting the expected productivity from experimental schemes and commercial oil sands plants. The productive capacity forecasts should cover the 1980 to 2000 period. Participants are requested to amplify on the range in future oil prices and relevant netbacks to the producers applicable to the respective forecasts. The discussion should also detail the anticipated increase in production costs during the forecast period, and the outlook for application of tertiary recovery methods.

ULTIMATE POTENTIAL

The Board requests that estimates of the total provincial ultimate potential of conventional crude oil be summarized as shown in Form I, attached. The form provides for the potential to be categorized as to light and medium, and heavy crude oil. It also provides for separate estimates of:

- initial established reserves,
- extensions and additions to existing reservoirs,
- new discoveries (including waterflood effects),
- tertiary recovery from established reserves,
- tertiary recovery from new discoveries, and
- additions resulting from deferred abandonment of established pools due to future higher prices.

To facilitate the comparison of reserves estimates, submittors are encouraged to detail reserve additions by geologic horizon and recovery mechanism. Assumptions regarding price, technology, and timing of additions should be clearly stated and to the extent possible, linked to the reserves additions.

The Board requests the 20-year forecast of the rate of growth of conventional crude oil reserves be summarized in accordance with the format illustrated in Form II.

The Board requests pentanes plus ultimate potential estimates in two categories:

- established reserves at 1 January 1980, and
- reserve additions.

To the extent possible, established reserve estimates should be based on individual gas processing plants. Assumptions respecting the estimated potential due to reserve additions should be included.

PRODUCTIVE CAPACITY

For purposes of this hearing, the Board defines productive capacity as the maximum sustainable capacity having regard for all field facilities required now and in the future for production, disposition and for pressure maintenance. Where there are constraints such as solution gas plant or pipeline capacity, such should be so noted, together with a statement as to the method and timing of any plans to remove the constraint.

The Board requests that productive capacity forecasts be categorized according to supply from

(a) light and medium, and heavy conventional crude oil

- established reserves at 1 January 1980
- reserve growth due to:
    - reserves additions to existing reservoirs(1)
    - new discoveries(2)
    - tertiary recovery - from established reserves
                         - from new discoveries
    - deferred abandonment(3)

(b) pentanes plus

- established reserves
- future reserves

(c) synthetic oil from oil sands on a commercial scale

- mining areas
- insitu areas

---

(1) includes development drilling and new waterflood but excludes reserves identified under established reserves

(2) inclusive of waterflood component

(3) resulting from increased product prices

/3

(d) experimental activity in

- conventional heavy oil
- oil sands

Submittors are asked to use the format shown in Forms III and IV when providing productivity of conventional oil forecasts for individual pools or the entire province, respectively. Where the estimator believes there is likely to be a future increase in the pool reserves due to further development drilling, infill drilling or enhanced recovery, it should describe its expectations and report its estimate of increased reserves and productive capacity.

In order to assist industry in updating productivity forecasts, the Board will provide, without comment, by about mid-March 1980, its latest estimates of reserves and productivity forecasts from established pools with greater than one million cubic metres of remaining recoverable reserves. The Board hopes this procedure will help operators to concentrate on those cases where significant changes or improvement should be made to the previous forecasts.

For those making capacity estimates from pentanes plus, commercial oil sands schemes, and experimental activities, the forecasts should be presented in tabular form reflecting the individual categories set out earlier in this letter.

With respect to all forecasts, a description of the methodology used and a summary of important assumptions should be included.

OTHER MATTERS

The Board further requests submittors to discuss the technical potential and economic incentives for accelerated infill drilling, exclusive of such infill drilling necessary to maintain the productivity forecast as submitted. The discussion should address and quantify the effects on incremental productivity and any incremental oil reserves attributable to the infill wells and should also deal with the associated economics of such actions.

In discussing the productivity of heavy oil, the Board requests elaboration on the potential and timing for heavy oil upgrading facilities. The discussion should include a review of economic conditions and technical developments required to both start and sustain upgrading facilities.

Inquiries concerning this letter may be directed to Mr. N. Guy Berndtsson at 261-8570 (403).

DATED at Calgary, Alberta on 11 February 1980.

J. A. Bray
Manager
Oil Department

Form I

SUMMARY OF ULTIMATE POTENTIAL OF CONVENTIONAL CRUDE OIL IN ALBERTA AS OF 1 JANUARY 1980

billions of cubic metres

	1	2	3	4	5
	Oil-In-Place		Recoverable Reserves		
	Light & Medium	Heavy	Light & Medium	Heavy	Total
Initial Established Reserves					
Expected Growth					
Extensions and additions to existing reservoirs					
New discoveries(1)					
Tertiary recovery from:					
. established reserves					
. new discoveries					
Deferred abandonment					
Sub-Total					
Ultimate Potential					
Cumulative Production					
Ultimate Remaining					

---

(1) including waterflood effects

Form II

GROWTH IN PROVED INITIAL RECOVERABLE RESERVES OF ALBERTA CONVENTIONAL CRUDE OIL
millions of cubic metres

	1	2	3	4	5	6	7	8	9
Year	Light & Medium			Heavy			Total		
	Primary & Waterflood	Tertiary Recovery Methods	Total	Primary & Waterflood	Tertiary Recovery Methods	Total	Primary & Waterflood	Tertiary Recovery Methods	Total
1980									
1981									
1982									
1983									
1984									
1985									
1986									
1987									
1988									
1989									
1990									
1991									
1992									
1993									
1994									
1995									
1996									
1997									
1998									
1999									
2000									

Form III

ENERGY RESOURCES CONSERVATION BOARD
PRODUCTIVE CAPACITY OF CRUDE OIL

POOL: ____________________

RECOVERY MECHANISM: ____________________

ESTABLISHED RESERVES OF OIL AT 80-01-01	10^3 m^3	PRODUCTIVE CAPACITY FORECAST* Year	m^3 per day
Initial oil-in-place	______	1980	________
Initial established reserves		1981	________
- Primary	______	1982	________
- Incremental enhanced	______	1983	________
- Total	______	1984	________
Cumulative production	______	1985	________
Remaining established reserves	______	1986	________
		1987	________
		1988	________
		1989	________
		1990	________
		1991	________
		1992	________
		1993	________
		1994	________
		1995	________
		1996	________
		1997	________
		1998	________
		1999	________
		2000	________

* Attributed to (please indicate and provide comments in text)

___ established reserves

potential reserve additions from:

- ___ development drilling
- ___ expanding existing recovery mechanism
- ___ new recovery mechanisms
- ___ infill drilling
- ___ other

Form IV

FORECAST OF ALBERTA PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL
UNRESTRICTED PRODUCTION
thousands of cubic metres per day

	1	2	3	4	5	6	7	8	9	10	11	12
Year	From Established Reserves As Of 1 January 1980			From Reserve Growth						Total Productive Capacity		
				Light & Medium			Heavy					
	Light & Medium	Heavy	Total	Primary & Waterflood[1]	Tertiary Recovery Methods	Total	Primary & Waterflood[1]	Tertiary Recovery Methods	Total	Light & Medium	Heavy	Total
1980												
1981												
1982												
1983												
1984												
1985												
1986												
1987												
1988												
1989												
1990												
1991												
1992												
1993												
1994												
1995												
1996												
1997												
1998												
1999												
2000												

---

[1] Includes new discoveries, reserve additions to existing reservoirs, and deferred abandonments.

APPENDIX A-3 TERMINOLOGY AND DEFINITIONS

A RESERVES TERMINOLOGY

1	Initial Volume In-Place	The gross volume of crude oil, bitumen, or raw natural gas calculated or interpreted to exist in a reservoir before any volume has been produced.
2	Established Reserves	Those resreves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing, or production, plus that judgement portion of contiguous recoverable reserves that are interpreted to exist, from geological, geophysical, or similar information, with reasonable certainty.
3	Initial Established Reserves	Established reserves prior to the deduction of any production.
4	Remaining	Initial established reserves less cumulative production.
5	Ultimate Potential	An estimate of the initial established reserves which will have been developed in an area by the time essentially all exploratory and development activity has

ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves and future additions through extensions and revisions to existing pools and the discovery of new pools.

The above reserves terminology and definitions, which were recommended by the Inter-Provincial Advisory Committee on Energy (IPACE), have been adopted by the Board. They can be expressed by the following simple formula:

Ultimate potential = Initial established reserves
+ additions to existing pools + future discoveries.

B OTHER TERMS

1	Crude Bitumen	A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds, and that in its naturally occurring viscous state is not recoverable at a commercial rate through a well. (The Oil and Gas Conservation Act, section 2.(1)10.)
2	Synthetic Crude Oil	A mixture, mainly of pentanes and heavier hydrocarbons, that may contain sulphur compounds, that is derived from crude bitumen and that is liquid at the conditions under which its volume is

		measured or estimated, and includes all other hydrocarbon mixtures so derived. (The Oil and Gas Conservation Act, section 2.(1)41.) (A more encompassing definition not yet formally adopted would reflect main feedstock in the name, eg. bitumen syncrude, coal syncrude, wood syncrude, etc.)
3	Crude Oil	A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas or condensate. (The Oil and Gas Conservation Act, section 2.(1)11.)
4	Conventional Crude Oil	A crude oil that is produced by means of a well from an underground reservoir and such production initially occurs naturally, at economic rates.
5	Heavy Crude Oil	Crude oil will be deemed to be heavy crude oil if it has density of 900 kg/m^3 or more, but the Board, in a particular case, may classify crude oil other-wise than in accordance with this criterion when

		appropriate, having regard to its market utilization and purchasers' classification. (Oil and Gas Conservation Regulation 10.030.)
6	Light-Medium Crude Oil	Crude oil will be deemed to be light-medium crude oil if it has a density of less than 900 kg/m^3; but the Board may classify light-medium density crude oil differently, having regard to its market utilization and purchasers' classification.
7	Condensate	A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or recoverable through a well from an underground reservoir and that is gaseous in its virgin reservoir state but is liquid at the conditions under which its volume measured or estimated. (The Oil and Gas Conservation Act, section 2.(1)8.)
8	Gas	Raw gas or marketable gas or any constituent of raw gas, condensate, crude bitumen, or crude oil that is recovered in processing and that is gaseous at the conditions under which its volume is measured or estimated. (The Oil and Gas Conservation Act, section 2.(1)20.)

9	Gas (Marketable)	A mixture mainly of methane originating from raw gas, if necessary through the processing of the raw gas for the removal or partial removal of some constituents, and which meets specifications for use as a domestic, commercial, or industrial fuel or as an industrial raw material. (The Oil and Gas Conservation Act, section 2.(1)26.)
10	Gas (Raw)	A mixture containing methane, other paraffinic hydrocarbons, nitrogen, carbon dioxide, hydrogen sulphide, helium, and minor impurities, or some of them, which is recovered or is recoverable at a well from an underground reservoir and which is gaseous at the conditions under which its volume is measured or estimated. (The Oil and Gas Conservation Act, section 2.(1)39.)
11	Maximum Efficient Rate	The maximum efficient rate at which oil can be produced without avoidable underground waste.
12	Maximum Rate Limitation (MRL)	The maximum rate of production prescribed for the avoidance of waste, after application of any applicable penalty factor. (Oil and Gas Conservation Regulation 1.020(2)10.)

13	Natural Gas Liquids (NGL)	Propane, butanes, or pentanes plus, or a combination of them, obtained from the processing of raw gas or condensate. (The Oil and Gas Conservation Act, section 2.(1)28.)
14	Oil	Condensate or crude oil, or a constituent of raw gas, condensate, or crude oil that is recoverd in processing, that is liquid at the conditions under which its volume is measured or estimated. (The Oil and Gas Conservation Act, section 2.(1)29.)
15	Oil Sands	Sands and other rock materials which contain crude bitumen and includes all other mineral substances in association therewith. (The Oil and Gas Conservation Act, section 2.(1)30.)
16	Oil Sands Deposit	A natural reservoir containing or appearing to contain an accumulation of oil sands separated or appearing to be separated by any other such accumulation. (The Oil and Gas Conservation Act, section 2.(1)31.)
17	Pentanes Plus	A mixture mainly of pentanes and heavier hydrocarbons which ordinarily may contain some butanes and which is obtained from the processing of raw gas, condensate, or crude oil. (The Oil and Gas Conservation Act, section 2.(1)32.)

18	Pool	A natural underground reservoir containing or appearing to contain an accumulation of oil or gas or both separated or appearing to be separated from any other such accumulation. (The Oil and Gas Conservation Act, section 2.(1)34.)
19	Primary Recovery	Recovery of oil by natural depletion processes only; measured as volume or fraction, of the oil so recovered.
20	Enhanced Recovery	Recovery of oil, gas or natural gas liquids by the application of an induced recovery process; measured as a volume or fraction of the additional oil, gas, or natural gas liquids so recovered. (Enhanced recovery reflects the conventional recovery methods of water flood or gas injection.)
21	Tertiary Recovery	Recovery of crude oil from a reservoir by an unconventional enhanced recovery method. (Excluded from this definition is the conventional, widely applied enhanced recovery methods of water flood and gas injection). For this report, the Board has accepted the term tertiary recovery in place of the less frequently used term

		"exotic recovery". Some tertiary recovery methods or processes are: (a) miscible floods using solvent (hydrocarbon) or carbon dioxide, (b) thermal floods using in situ combustion or steam injection
22	Solvent	A suitable mixture of hydrocarbons ranging from methane to pentanes plus, but consisting largely of methane, ethane, propane, and butanes, for use in enhanced-recovery operations.
23	Experimental Scheme	A pilot test to evaluate techniques for recovery of crude bitumen, crude oil, condensate or gas using methods that are considered untried and unproven in the particular situation.
24	Infill Drilling	The drilling of wells in addition to the wells drilled in the drilling spacing unit under which a mature pool was developed.
25	Discoveries/Additions	As well as new discoveries, the term used in this report includes extensions and other miscellaneous additions to existing pools and the application of conventional enhanced recovery methods to those resources.

26	Productive Capacity	The maximum sustainable capacity having regard for maximum efficient rates and for all field facilities required now and in the future for production, processing, storage and transport of crude oil and equivalents. Productive capacity from oil and gas reservoirs gradually declines in a predictable manner in relation to the depleting resource.

C SI UNITS

This report has been prepared in the International System of Units (SI). Conversion factors that may be used in calculating the imperial equivalent of the SI Units used in the report are listed below:

1 cubic metre of oil or pentanes plus (equilibrium pressure and 15° Celsius)	=	6.292 9 Canadian barrels (equilibrium pressure and 60°F)
1 cubic metre of natural gas (101.325 kilopascals and 15° Celsius)	=	35.494 cubic feet (14.65 psia and 60°F)
1 tonne	=	0.984 21 (U.K.) long tons
	=	1.102 3 short tons
1 kilojoule	=	0.948 21 British thermal units (Btu as defined in Federal Gas Inspection Act (60°-61°F)

D SYMBOLS

Metric		Imperial	
°C	degree Celsius	bbl	barrel
d	day	Btu	British thermal unit
ha	hectare	cf	cubic foot
J	joule	d	day
kg	kilogram	°F	degree Fahrenheit
kPa	kilopascal	psia	pounds per square inch absolute
M	mega	stb	stock tank barrel
m	metre		
mPa·s	milipascal x second		

APPENDIX A-4 ERCB Forecast of Productive Capacity from Remaining Established Reserves of Conventional Crude Oil

The Board's forecast of productive capacity attributed to the remaining established reserves of light-medium and heavy crude oil previously published in Information Letter, IL 80-6, is summarized in the following tables. The crude oil productivity forecasts and estimates of reserves are for developed pools with greater than one million cubic metres remaining established reserves.

It is tabulated by pipeline system. It is emphasized that the forecasts are for the current depletion mechanisms of developed pools. In a few pools there are some differences noted between the currently established reserve and the reserve used in the productivity forecast. The differences occur because of adjustments made in pool reserves to obtain an acceptable productivity profile, consistent with available pool information and computer program limitations. The net total of the differences is nominal and the Board has not adopted these adjustments for its provincial reserves.

PROVINCIAL SUMMARY
FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979

Pipeline	Table	Established Reserves 103 m3		Productive Capacity m3/d											
		Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Light & Medium Crude Oil															
Alberta Oil Sands	1	128 235	19 029	14 040	10 484	7 602	5 516	4 005	2 911	2 119	1 546	1 130	829	171	-
Bow River	2	11 080	5 412	1 252	1 178	1 076	985	902	827	760	699	644	589	371	218
Cremona	3	29 561	7 464	2 705	2 302	2 001	1 744	1 531	1 343	1 186	931	828	720	353	203
Federated	4	385 168	180 531	34 744	32 641	30 572	28 639	25 982	23 396	21 100	19 060	17 240	15 619	9 731	6 274
Gibson	5	10 175	4 548	958	843	721	632	562	506	459	421	388	360	246	195
Gulf Alberta	6	112 112	35 917	13 346	10 734	9 048	7 822	6 890	6 128	5 477	4 835	4 142	3 527	2 021	691
Imperial Ellerslie	7	60 403	14 845	5 198	4 691	4 139	3 722	3 194	2 650	2 219	1 872	1 592	1 297	610	338
Imperial Excelsior	8	6 629	1 142	882	757	600	477	380	305	224	179	143	114	-	-
Imperial Leduc	9	58 021	2 004	1 624	1 210	994	840	725	637	568	499	454	401	229	133
Murphy	10	2 542	1 139	251	251	248	243	238	235	231	229	226	211	79	-
Norcen	11	15 000	1 358	795	652	523	419	336	269	216	173	139	111	-	-
Peace Pipe	12	139 356	63 402	14 540	14 086	13 620	12 778	11 689	10 557	9 382	8 351	7 405	6 614	3 833	2 226
Pembina	13	319 683	153 636	19 114	18 536	17 637	16 856	16 067	15 226	14 093	12 827	11 506	10 385	6 530	4 392
Rainbow	14	240 340	121 016	27 592	27 474	27 165	25 880	23 386	20 802	18 499	16 468	14 676	13 078	7 000	3 742
Rangeland	15	81 821	41 808	8 214	7 461	6 753	6 185	5 614	5 065	4 598	4 197	3 847	3 470	2 042	1 121
Texaco	16	152 765	50 654	25 282	22 217	17 330	13 631	10 816	8 651	6 968	5 653	4 617	3 793	1 542	700
Twining	17	8 629	6 319	756	721	695	664	614	572	533	500	471	444	319	261
Valley	18	20 791	155	499	429	369	318	273	235	202	174	150	129	-	-
Tank Car & Truck	19	16 427	12 763	2 439	2 439	2 397	2 341	2 289	2 243	2 179	2 025	1 832	1 657	1 007	612
Total Light & Medium		1 798 738	723 142	174 231	159 106	143 490	129 692	115 493	102 558	91 013	80 639	71 430	63 328	36 084	21 106
Heavy Crude Oil															
Bow River	20	44 970	19 412	7 522	6 324	5 351	4 564	3 931	3 407	2 977	2 618	2 317	2 064	906	519
BP Oil	21	5 403	2 553	815	691	613	541	480	428	383	344	310	281	146	32
Husky Oil	22	24 212	10 459	3 978	3 560	3 095	2 713	2 397	2 127	1 884	1 675	1 498	1 345	629	389
Imperial Ellerslie	23	63	60	3	3	3	3	3	3	3	3	3	3	3	3
Murphy	24	1 527	656	150	150	150	150	150	150	150	150	150	137	-	-
Peace Pipe	25	175	106	29	26	23	21	19	17	15	14	12	11	7	5
Pembina	26	62	24	33	29	24	21	17	15	12	11	9	8	4	2
Rangeland	27	125	83	12	12	12	12	12	12	12	12	12	12	12	8
Tank Car & Truck	28	8 815	3 296	1 055	952	880	817	766	726	691	654	539	492	96	62
Total Heavy		85 352	36 649	13 597	11 747	10 151	8 842	7 775	6 885	6 127	5 481	4 850	4 353	1 803	1 020
TOTAL CRUDE OIL		1 884 090	759 791	187 828	170 853	153 641	138 534	123 268	109 443	97 140	86 120	76 280	67 681	37 887	22 126

TABLE 1
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
ALBERTA OIL SANDS PIPELINE - REDWATER (LIGHT AND MEDIUM CRUDE OIL)

Pool	Established Reserves 103m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Redwater D-3 WF	128 000	18 836	14 000	10 444	7 562	5 476	3 965	2 871	2 079	1 506	1 090	790	157	-
Others	235	193	40	40	40	40	40	40	40	40	40	39	14	-
Total	128 235	19 029	14 040	10 484	7 602	5 516	4 005	2 911	2 119	1 546	1 130	829	171	-

Recovery Mechanism Abbreviations Used:
WF - Waterflood
SF - Solvent Flood
GF - Gas flood
P - Primary

TABLE 2
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
BOW RIVER PIPELINE (LIGHT AND MEDIUM CRUDE OIL)

Pool	Established Reserves 103m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Provost Vik CAK & Mann E P & WF	9 310	4 044	1 090	1 027	929	841	760	688	622	563	510	461	280	169
Youngstown Arcs	934a	766	50	50	50	50	50	50	50	50	49	44	27	16
Others	836	602	112	101	97	94	92	89	88	86	85	84	64	33
Total	11 080	5 412	1 252	1 178	1 076	985	902	827	760	699	644	589	371	218

Recovery Mechanism Abbreviations Used:
WF - Waterflood
SF - Solvent flood
GF - Gas flood

Reserve Used in Forecast
a 467

TABLE 3
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
CREMONA PIPELINE (LIGHT AND MEDIUM CRUDE OIL)

Pool	Established Reserves 103m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Crossfield Cardium A WF	2 790a	154	120	120	119	109	100	92	85	-	-	-	-	-
Garrington Cardium A & B - 27%	732	109	43	40	37	33	30	28	26	24	22	-	-	-
Harmattan East Rundle WF	13 100	4 605	1 250	1 097	978	874	784	705	636	576	522	474	303	203
Harmattan Elkton Rundle C	8 570	1 506	915	724	568	448	356	284	227	183	148	121	-	-
Westward Ho Rundle A WF	1 760	321	95	92	85	78	72	66	62	57	53	50	-	-
Others	2 609	769	282	229	214	202	189	168	150	91	83	75	50	-
Total	29 561	7 464	2 705	2 302	2 001	1 744	1 531	1 343	1 186	931	828	720	353	203

Recovery Mechanism Abbreviations Used:
WF - Waterflood
SF - Solvent flood
GF - Gas flood

Reserve Used in Forecast
a 2 930

TABLE 4
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
FEDERATED PIPELINES LTD. (LIGHT AND MEDIUM CRUDE OIL)

Pool	Established Reserves 103m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Carson Creek N BHL A WF	6 790	3 397	1 100	1 004	890	789	700	620	550	488	433	384	210	115
Carson Creek N BHL B WF	19 900	8 975	2 400	2 388	2 140	1 916	1 717	1 537	1 377	1 234	1 105	990	571	329
Judy Creek BHL A WF	62 000	24 788	6 600	6 600	6 600	6 600	5 868	5 049	4 344	3 738	3 216	2 767	1 305	615
Judy Creek BHL B WF	19 900	7 844	1 850	1 850	1 850	1 850	1 670	1 481	1 313	1 164	1 032	916	502	275
Meekwap D-2A P & WF	4 160	2 528	635	635	607	530	465	410	363	323	288	259	157	102
Morinville D-3B - 7%	107	48	9	9	9	8	7	6	6	6	5	5	3	2
Swan Hills BHL A & B P & WF	127 000a	59 043	9 600	8 630	7 901	7 242	6 645	6 104	5 613	5 167	4 762	4 392	2 974	2 058
Swan Hills BHL C P & WF	32 600b	18 258	2 000	1 881	1 740	1 612	1 496	1 390	1 293	1 205	1 124	1 050	758	561
Swan Hills S BHL A & B P, WF & SF	81 200	41 136	8 325	7 745	7 090	6 498	5 963	5 477	5 037	4 637	4 272	3 941	2 668	1 846
Virginia Hills BHL P & WF	30 000c	13 569	1 900	1 698	1 552	1 418	1 296	1 184	1 082	989	904	826	526	335
Others	1 511	945	325	201	193	176	155	138	122	109	99	89	57	36
Total	385 168	180 531	34 744	32 641	30 572	28 639	25 982	23 396	21 100	19 060	17 240	15 619	9 731	6 274

Recovery Mechanism Abbreviations Used:
WF - Waterflood
SF - Solvent flood
GF - Gas flood

Reserve Used in Forecast
a 114 000
b 26 000
c 24 000

TABLE 5
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
GIBSON PETROLEUM COMPANY LIMITED (LIGHT AND MEDIUM CRUDE OIL)

Pool	Established Reserves 103m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Bellshill Lake Blairmore	9 540	4 382	890	784	670	586	521	469	426	390	360	334	246	195
Others	635	166	68	59	51	46	41	37	33	31	28	26	-	-
Total	10 175	4 548	958	843	721	632	562	506	459	421	388	360	246	195

TABLE 6
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
GULF ALBERTA PIPELINE CO. LTD. (LIGHT AND MEDIUM CRUDE OIL)

Pool	Established Reserves 103m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Clive D-2A WF	3 430	1 968	390	390	390	390	390	390	361	327	295	267	162	98
Clive D-3A P & WF	6 940	3 544	825	825	825	825	825	825	738	635	546	470	222	105
Drumheller D-2A	1 210	220	140	105	86	70	58	47	39	31	26	-	-	-
Drumheller D-2B	1 640	821	180	180	180	174	157	142	129	117	105	95	58	35
Duhamel D-2A	920a	53	55	53	43	35	29	24	19	16	-	-	-	-
Duhamel D-3B	1 120	146	70	59	50	43	37	31	27	23	19	16	-	-
Erskine D-3	4 150b	959	155	155	155	155	155	155	155	155	144	131	84	-
Fenn Big Valley D-2A	42 000	12 008	7 750	5 560	4 143	3 146	2 417	1 882	1 483	1 181	951	773	306	140
Fenn D-3F	1 650c	237	425	279	213	165	130	104	84	69	57	-	-	-
Fenn West D-2A	1 020	144	120	97	76	60	47	-	-	-	-	-	-	-
Hussar Glauconitic A	3 270	1 051	400	320	284	252	223	198	176	156	138	123	67	-
Joffre Viking P & WF	6 160	287	140	124	108	94	83	73	65	57	-	-	-	-
Joffre D-2 P & WF	9 650	3 850	480	480	480	480	480	480	480	480	480	480	419	254
Malmo D-2A	1 110	50	30	30	30	26	21	-	-	-	-	-	-	-
New Norway D-2	1 140d	111	115	94	78	65	55	46	38	32	26	22	-	-
Stettler D-2A P & WF	3 790e	184	165	157	142	129	117	106	95	86	-	-	-	-
Stettler D-3A	3 690	1 176	325	305	276	251	228	207	188	171	156	142	91	59
West Drumheller D-2A	4 370	572	300	240	208	181	157	137	119	103	90	-	-	-
Others	14 852	8 536	1 281	1 281	1 281	1 281	1 281	1 281	1 281	1 196	1 109	1 008	612	-
Total	112 112	35 917	13 346	10 734	9 048	7 822	6 890	6 128	5 477	4 835	4 142	3 527	2 021	691

Recovery Mechanism Abbreviations Used:
WF - Waterflood
SF - Solvent flood
GF - Gas flood

Reserve Used in Forecast	
a	966
b	3 940
c	1 980
d	1 250
e	3 980

TABLE 7
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
IMPERIAL PIPELINE CO. (ELLERSLIE) (LIGHT AND MEDIUM CRUDE OIL)

Pool	Established Reserves 103 m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Acheson D-3A WF	17 300	4 481	2 350	1 940	1 488	1 161	922	743	607	502	419	354	168	92
Golden Spike D-2A WF	958a	628	10	10	10	10	10	10	10	10	10	10	6	-
Golden Spike D-3A P & GF	33 500	7 084	1 900	1 900	1 900	1 900	1 684	1 381	1 146	960	812	692	344	193
Morinville D-3B - 93Z	1 423	644	116	116	115	105	96	88	81	74	68	63	44	31
Big Lake D-3A	2 670	806	335	270	224	187	158	134	114	98	85	74	39	22
St. Albert D-3B	909	225	115	99	78	62	50	41	34	28	23	19	9	-
Others	3 643	977	372	356	324	297	274	253	227	200	175	85	-	-
Total	60 403	14 845	5 198	4 691	4 139	3 722	3 194	2 650	2 219	1 872	1 592	1 297	610	338

Recovery Mechanism Abbreviations Used:
WF - Waterflood
SF - Solvent flood
GF - Gas flood

Reserve Used in Forecast
a 383

TABLE 8
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
IMPERIAL PIPELINE CO. (EXCELSIOR) (LIGHT AND MEDIUM CRUDE OIL)

Pool	Established Reserves 103m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Excelsior D-2	4 210a	669	650	550	427	332	258	201	156	121	94	73	-	-
Fairydell D-3A	1 800	357	175	153	126	104	86	72	60	50	42	35	-	-
Others	619	116	57	54	47	41	36	32	8	8	7	6	-	-
Total	6 629	1 142	882	757	600	477	380	305	224	179	143	114	-	-

Reserve Used in Forecast
a 4 630

TABLE 9
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
IMPERIAL PIPELINE CO. (LEDUC) (LIGHT AND MEDIUM CRUDE OIL)

Pool	Established Reserves 103m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Leduc - Woodbend D-2A WF	14 700	948	160	160	160	160	160	160	160	160	159	143	87	53
Leduc - Woodbend D-3B WF	3 260	49	3	3	3	3	3	3	3	3	3	3	3	3
Leduc - Woodbend D-3A WF	37 000a	514	1 200	867	677	544	446	373	316	272	236	207	119	77
Leduc - Woodbend D-3B	1 190	28	6	6	6	6	6	6	6	6	6	6	-	-
Others	1 871	465	255	174	148	127	110	95	83	58	50	42	20	-
Total	58 021	2 004	1 624	1 210	994	840	725	637	568	499	454	401	229	133

Recovery Mechanism Abbreviations Used:
WF - Waterflood
SF - Solvent flood
GF - Gas flood

Reserve Used in Forecast
a 39 000

TABLE 10
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
MURPHY OIL COMPANY LTD. (LIGHT AND MEDIUM CRUDE OIL)

Pool	Established Reserves 103m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Others	2 542	1 139	251	251	248	243	238	235	231	229	226	211	79	-

TABLE 11
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
NORCEN ENERGY RESOURCES LTD. (LIGHT AND MEDIUM CRUDE OIL)

Pool	Established Reserves 10^3m^3		Productive Capacity m^3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Joarcam Viking WF & GF	15 000	1 358	795	652	523	419	336	269	216	173	139	111	-	-

Recovery Mechanism Abbreviations Used:
WF - Waterflood
SF - Solvent flood
GF - Gas flood

TABLE 12
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
PEACE PIPE LINE LTD. (LIGHT AND MEDIUM CRUDE OIL)

Pool	Established Reserves 103 m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Ante Creek BHL SF	3 560a	2 258	200	200	200	200	200	200	200	200	200	200	200	156
Cherhill Banff A WF	3 500b	2 566	230	230	230	230	230	230	230	221	199	180	113	75
Goose River BHL WF	7 820	3 905	750	685	633	586	543	504	469	436	406	378	270	196
Kaybob BHL A WF	20 000	7 976	2 200	2 096	1 862	1 657	1 476	1 317	1 177	1 053	943	845	498	302
Kaybob South Triassic A P & WF	13 900	6 756	1 975	1 975	1 975	1 720	1 495	1 300	1 129	982	853	742	368	182
Nipisi Gilwood A - 51.5% P & WF	24 256	11 156	3 090	3 090	3 090	3 010	2 590	2 229	1 918	1 650	1 420	1 222	576	271
Nipisi Gilwood C - 51.5% P & WF	932c	720	41	41	41	41	41	41	41	41	41	41	36	22
Red Earth Granite Wash A	4 320	2 231	445	445	445	445	445	433	391	354	320	290	176	107
Red Earth Granite Wash E	1 330d	785	85	85	85	78	70	62	56	50	45	40	23	-
Simonette D-3 WF	7 560	2 774	625	625	588	534	485	442	403	368	336	307	200	134
Snipe Lake BHL WF	12 400e	5 802	750	703	657	615	576	540	507	477	449	423	319	246
Sturgeon Lake D-3	3 530	803	300	300	296	245	204	171	144	121	103	87	-	-
Sturgeon Lake South D-3	24 900	10 064	2 415	2 415	2 415	2 415	2 415	2 237	1 924	1 656	1 425	1 226	578	272
Sunset Triassic A WF	1 030f	677	70	70	70	70	70	70	70	70	70	70	49	-
Utikuma Keg River Sandstone A - 16%	952	561	152	139	126	114	103	93	84	76	69	62	38	23
Windfall D-3A	1 530g	128	500	275	197	143	104	77	57	43	-	-	-	-
Others	7 836	4 240	712	712	710	675	642	611	582	553	526	501	389	240
Total	139 356	63 402	14 540	14 086	13 620	12 778	11 689	10 557	9 382	8 351	7 405	6 614	3 833	2 226

Recovery Mechanism Abbreviations Used:
WF - Waterflood
SF - Solvent flood
GF - Gas flood

Reserve Used in Forecast

a	3 200	d	865
b	2 450	e	11 200
c	513	f	773
		g	1 910

TABLE 13

SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
PEMBINA PIPE LINE LTD. (LIGHT AND MEDIUM CRUDE OIL)

Pool	Established Reserves 10³m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Bigoray Nisku D WF	880	773	160	160	160	160	160	160	160	160	143	119	48	20
Bigoray Nisku F WF	1 350	1 193	309	309	309	309	309	288	241	201	168	140	57	23
Bigoray Ostracod P & WF	994	354	85	80	73	67	61	56	52	48	44	41	29	21
Brazeau River Nisku A	2 120	1 870	485	485	485	485	485	449	374	313	261	218	88	36
Brazeau River Nisku D	1 200	1 104	270	270	270	270	270	270	235	196	164	137	56	23
Brazeau River Nisku E	900	806	207	207	207	207	207	198	165	138	115	96	39	16
Cyn-Pem Cardium A WF	2 180	752	325	259	219	186	159	137	119	103	90	79	44	-
Niton Basal Quartz B WF	2 040	1 453	230	230	230	230	230	230	230	227	202	182	113	75
Pembina Belly River B P & WF	9 550	5 179	963	963	963	963	963	963	876	793	717	649	393	238
Pembina Belly River C P & WF	2 780	1 646	500	484	430	381	338	300	266	236	209	185	101	56
Pembina Belly River I P & WF	2 230a	1 506	115	115	115	115	115	115	115	115	115	115	115	75
Pembina Belly River L P & WF	1 350b	1 028	80	80	80	80	80	80	80	80	80	80	80	80
Pembina Belly River M WF	1 820	1 081	150	150	150	150	150	150	150	150	150	150	115	69
Pembina Belly River O P&WF	1 230	552	135	135	135	135	135	128	116	105	95	86	52	-
Pembina Cardium P, WF, SF & GF	239 000c	96 402	9 000	8 509	7 711	7 031	6 441	5 945	5 490	5 113	4 766	4 460	3 324	2 608
Pembina Nisku D WF	2 550	2 319	585	585	585	585	585	570	477	398	332	277	112	46
Pembina Nisku G	1 200	1 115	278	278	278	278	278	277	232	193	162	135	55	22
Pembina Nisku K	840	758	194	194	194	194	194	184	154	128	107	89	36	15
Pembina Nisku L	1 000	957	200	200	200	200	200	200	200	200	169	141	57	23
Pembina Nisku Other	12 465	11 628	2 610	2 610	2 610	2 610	2 610	2 610	2 610	2 322	1 938	1 618	656	266
Westpem Nisku A	1 000	886	265	265	265	265	226	189	158	132	110	92	37	15
Willesden Green Cardium - 70% P,WF & SF	25 760d	17 042	1 435	1 435	1 435	1 435	1 387	1 277	1 178	1 091	1 013	943	682	517
Others	5 244	3 237	533	533	533	520	484	450	415	385	356	333	241	148
Total	319 683	153 536	19 114	18 536	17 637	16 856	16 067	15 226	14 093	12 827	11 506	10 365	6 530	4 392

Reserve Used in Forecast	
a	1 670
b	1 080
c	223 900
d	20 580

Recovery Mechanism Abbreviations Used:

WF - Waterflood

SF - Solvent flood

GF - Gas flood

TABLE 14
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
RAINBOW PIPE LINE COMPANY LTD. (LIGHT AND MEDIUM CRUDE OIL)

Pool	Established Reserves 103m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Black Keg River A WF	1 400a	872	55	51	45	40	36	32	28	25	22	20	11	6
Golden Slave Point A	3 100	2 132	450	450	450	450	407	368	333	301	273	247	149	91
Larne Field	390	160	30	30	30	30	30	30	30	30	30	30	24	-
Mitsue Gilwood A P & WF	54 200	25 621	7 250	7 250	7 250	6 836	5 882	5 061	4 354	3 747	3 223	2 774	1 308	617
Nipisi Gilwood A - 48.5% P & WF	22 844	10 506	2 910	2 910	2 910	2 834	2 440	2 099	1 806	1 554	1 337	1 150	542	256
Nipisi Gilwood C - 48.5% P & WF	878b	678	39	39	39	39	39	39	39	39	39	39	33	20
Rainbow IS No. 1 SF														
Rainbow Keg River A	12 600	6 594	1 150	1 150	1 150	1 150	1 150	1 150	1 150	1 138	1 010	895	491	269
Rainbow Keg River B	25 600	11 550	2 500	2 500	2 500	2 500	2 457	2 179	1 933	1 714	1 520	1 348	739	405
Others	14 215	7 607	2 035	2 035	2 035	2 035	1 836	1 498	1 198	944	836	742	407	224
Rainbow IS No. 2 SF	4 566	2 453	750	750	696	605	526	457	398	345	300	261	129	64
Rainbow IS No. 11 SF														
Rainbow Keg River AA	12 400	7 123	1 050	1 050	1 050	1 050	1 050	1 050	1 050	1 050	1 050	1 050	636	349
Others	4 092	1 838	300	300	300	300	300	300	300	300	300	300	139	76
Rainbow Keg River F WF	19 100	9 348	2 789	2 789	2 789	2 416	2 079	1 789	1 539	1 324	1 140	980	462	218
Rainbow Keg River I WF	3 260	1 602	407	407	407	361	320	284	252	223	198	175	96	53
Rainbow Keg River U	1 650c	1 138	85	85	85	85	78	70	64	58	52	47	29	17
Rainbow Keg River II WF	2 310	1 097	450	424	354	296	247	206	172	143	120	100	40	16
Rainbow Field Other	6 881d	4 060	550	550	550	550	550	550	503	455	412	372	226	137
Rainbow South Keg River A WF	3 080e	1 619	145	145	145	145	145	145	143	129	117	106	64	39
Rainbow South Keg River B SF	5 210	2 903	695	695	695	668	592	525	466	413	366	325	178	98
Rainbow South Keg River E WF	4 010	2 269	380	380	380	380	380	380	380	380	364	323	177	97
Rainbow South Keg River G WF	1 820	1 126	295	295	295	270	237	208	183	160	141	124	65	34
Rainbow South Keg River N	1 000	998	5	5	5	5	5	5	5	5	5	5	5	5
Rainbow South Field Other	1 046	628	30	30	30	30	30	30	30	30	30	30	30	30
Shekilie Field	800	345	71	71	71	71	71	71	71	71	64	56	29	-
Sousa Field	952	832	73	73	73	73	73	73	73	73	73	73	73	73
Tehze Keg River A WF	1 350	867	125	125	125	125	125	125	125	125	125	125	82	45
Utikuma Keg River Sandstone A - 84%	4 998	2 946	798	731	661	598	541	490	443	401	363	328	199	120
Virgo Field	7 799f	3 089	580	580	580	580	528	469	415	368	327	290	159	87
Zama Field	15 641g	6 868	1 165	1 144	1 035	937	847	767	694	628	568	514	311	189
Others	3 148	2 138	430	430	430	421	385	352	322	295	271	249	167	107
Total	240 340	121 016	27 592	27 474	27 165	25 880	23 386	20 802	18 499	16 468	14 676	13 078	7 000	3 742

Recovery Mechanism Abbreviations Used:
WF - Waterflood
SF - Solvent flood
GF - Gas flood

Reserve Use in Forecast

a	700	d	5 850
b	483	e	2 310
c	908	f	7 020
		g	13 294

TABLE 15
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
RANGELAND PIPE LINE COMPANY LTD. (LIGHT AND MEDIUM CRUDE OIL)

Pool	Established Reserves 103 m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Caroline Cardium E P & GF	1 020	713	370	298	248	207	173	145	121	101	84	70	-	-
Caroline Viking A	1 110	557	225	194	173	155	139	126	113	103	94	85	-	-
Ferrier Cardium D P & WF	1 920	892	270	234	206	182	164	148	134	123	113	105	74	56
Ferrier Cardium E P & WF	4 850a	3 576	450	435	396	364	336	311	291	271	254	238	181	143
Ferrier Cardium G P & WF	1 480	1 314	130	130	130	130	130	130	130	130	130	127	98	79
Garrington Cardium A&B - 73% P & WF	1 978	296	117	110	99	91	83	76	71	65	61	-	-	-
Gilby Viking A P & WF	2 750	417	70	70	70	70	70	70	70	70	70	70	47	-
Gilby Basal Mannville B P & WF	2 400b	1 668	100	100	100	100	100	100	100	100	94	88	66	53
Gilby Jurassic B WF	3 670	1 863	340	276	256	238	223	210	198	186	176	167	131	106
Innisfail D-3	11 800	2 936	1 845	1 451	1 128	877	681	530	412	320	249	193	-	-
Medicine River Glauconitic A P & WF	2 020	1 110	200	200	200	200	199	183	169	157	145	135	98	74
Medicine River Jurassic A WF	1 800	1 261	250	205	177	152	131	113	97	83	72	62	-	-
Medicine River Jurassic C P & WF	3 100c	2 154	120	120	120	120	120	120	120	120	120	112	80	60
Medicine River Jurassic D WF	3 080d	1 991	215	213	194	178	163	150	139	129	120	112	81	62
Medicine River Pekisko I	1 330e	771	75	75	75	75	75	75	75	75	75	75	75	51
Ricinus Cardium A	2 880	2 319	325	325	295	272	251	232	216	202	189	177	135	106
Sundre Rundle A WF	5 130	1 209	355	350	303	263	230	201	176	155	137	121	68	40
Sylvan Lake Pekisko B	2 300	1 316	270	261	238	217	199	183	168	155	144	133	95	70
Willesden Green Cardium A - 30% P, WF & SF	11 040f	7 304	615	615	615	615	595	547	505	467	434	404	293	221
Wimborne D-3A	1 950g	350	410	337	268	217	178	147	123	104	89	76	39	-
Others	14 213h	7 791	1 462	1 462	1 462	1 462	1 374	1 268	1 170	1 081	997	920	481	-
Total	81 821	41 808	8 214	7 461	6 753	6 185	5 614	5 065	4 598	4 197	3 847	3 470	2 042	1 121

Reserve Used in Forecast:
a 4 120
b 1 620
c 1 860
d 2 310
e 1 180
f 8 820
g 2 440
h 12 502

Recovery Mechanism Abbreviations Used:
WF - Waterflood
SF - Solvent flood
GF - Gas flood

TABLE 16
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM PROVED REMAINING RECOVERABLE RESERVES AS OF 31 DECEMBER 1979 FOR
TEXACO CANADA RESOURCES LTD. (LIGHT AND MEDIUM CRUDE OIL)

Pool	Established Reserves 103m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Bonnie Glen D-3A	80 700	28 360	13 500	12 543	9 793	7 707	6 117	4 894	3 944	3 200	2 614	2 147	870	393
Glen Park D-3A	3 350	1 009	500	398	316	254	207	170	141	118	99	85	41	22
Westerose D-3	17 000	4 586	3 019	2 254	1 688	1 274	970	745	574	446	349	274	89	33
Wizard Lake D-3A SF	51 300	16 601	8 250	7 009	5 520	4 383	3 509	2 829	2 296	1 876	1 542	1 274	530	244
Others	415	98	13	13	13	13	13	13	13	13	13	13	12	8
Total	152 765	50 654	25 282	22 217	17 330	13 631	10 816	8 651	6 968	5 653	4 617	3 793	1 542	700

Recovery Mechanism Abbreviations Used:
WF - Waterflood
SF - Solvent flood
GF - Gas flood

TABLE 17
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
TWINNING PIPE LINE (LIGHT AND MEDIUM CRUDE OIL)

Pool	Established Reserves 103 m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Twining Rundle A & L Mann. A	7 120a	5 466	540	540	540	528	494	464	435	410	388	366	288	232
Twining North Rundle	911	401	185	150	124	105	89	77	67	59	52	47	-	-
Others	598	452	31	31	31	31	31	31	31	31	31	31	31	29
Total	8 629	6 319	756	721	695	664	614	572	533	500	471	444	319	261

Reserve Used in Forecast:
a 6 410

TABLE 18
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
VALLEY PIPE LINE (LIGHT AND MEDIUM CRUDE OIL)

Pool	Established Reserves 103 m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Turner Valley Rundle P & WF	20 700a	71	498	429	369	318	273	235	202	174	150	129	-	-
Others	91	84	1	-	-	-	-	-	-	-	-	-	-	-
Total	20 791	155	499	429	369	318	273	235	202	174	150	129	-	-

Recovery Mechanism Abbreviations Used:
WF - Waterflood
SF - Solvent flood
GF - Gas flood

Reserve Used in Forecast
a 21 740

TABLE 19
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
TRUCK AND TANK CAR (LIGHT AND MEDIUM CRUDE OIL)

Pool	Established Reserves 103 m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Boundary Lk South Triassic SF & WF	3 580	2 109	525	525	488	442	400	362	327	296	268	242	147	89
Homeglen Rimbey D-3	1 100	6	-	-	-	-	-	-	-	-	-	-	-	-
Undefined & Confidential	8 658	8 526	1 500	1 500	1 500	1 500	1 500	1 500	1 500	1 410	1 276	1 154	700	424
Others	3 089	2 122	414	414	409	399	389	381	352	319	288	261	160	99
Total	16 427	12 763	2 439	2 439	2 397	2 341	2 289	2 243	2 179	2 025	1 832	1 657	1 007	612

Recovery Mechanism Abbreviation
WF - Waterflood
SF - Solvent flood
GF - Gas flood

TABLE 20
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
BOW RIVER PIPELINE (HEAVY CRUDE OIL)

Pool	Established Reserves 103 m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Bantry Mannville A P & WF	6 390	2 164	560	501	448	403	365	331	302	276	253	233	161	117
Bantry Mannville D	1 250	586	125	125	125	119	109	101	93	86	79	74	53	40
Countess Upper Mannville B WF	1 230	499	180	153	132	115	101	88	77	68	60	54	31	19
Countess Upper Mannville D P & WF	4 960a	2 012	1 085	871	710	584	486	407	343	292	250	215	109	61
Countess Upper Mannville H WF	1 750b	355	350	258	204	163	132	107	88	73	61	51	23	-
Countess Upper Mannville O WF	1 200c	913	125	113	103	93	86	78	72	66	61	57	40	29
Grand Forks Upper Mannville B WF	1 050	628	340	256	207	167	137	112	92	75	62	52	22	-
Grand Forks Lower Mannville D WF	5 450	3 322	1 400	1 206	961	777	637	527	441	373	318	272	139	79
Grand Forks Lower Mannville K WF	1 220d	684	370	287	240	203	174	150	131	114	101	90	53	34
Hays Lower Mannville A WF	1 420e	348	210	183	156	134	117	103	91	81	73	66	42	29
Jenner Upper Mannville E WF	953f	390	75	75	75	69	62	56	50	46	41	38	25	-
Lathom Upper Mannville A WF	1 600g	521	300	245	200	165	137	114	97	82	70	60	31	17
Provost Upper Mannville B	1 020h	817	85	85	85	85	85	85	85	85	85	85	77	45
Taber Mannville D P & WF	2 280	990	250	219	196	176	159	144	131	119	109	100	68	49
Taber South Mannville A WF	1 370i	633	90	89	81	74	67	62	57	53	49	45	32	-
Taber South Mannville B P & WF	1 750j	155	152	124	100	82	69	59	51	44	39	35	-	-
Others	10 077	4 395	1 825	1 534	1 328	1 155	1 008	883	776	685	606	537	-	-
Total	44 970	19 412	7 522	6 324	5 351	4 564	3 931	3 407	2 977	2 618	2 317	2 064	906	519

Reserves Used in Forecast:

a	5 400
b	2 020
c	900
d	1 460
e	1 780
f	858
g	1 760
h	816
i	1 100
j	1 900

Recovery Mechanism Abbreviations Used:
WF - Waterflood
SF - Solvent flood
GF - Gas flood

TABLE 21
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
BP PIPELINE (HEAVY CRUDE OIL)

Pool	Established Reserves 103 m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Chauvin Mannville A P&WF	1 230	323	95	95	91	82	74	67	61	56	51	47	-	-
Chauvin South Sparky A&B P&WF	1 530a	774	120	112	102	93	86	79	73	68	63	59	43	32
Others	2 643	1 456	600	484	420	366	320	282	249	220	196	175	103	-
Total	5 403	2 553	815	691	613	541	480	428	383	344	310	281	146	32

Recovery Mechanism Abbreviations Used:
WF - Waterflood
SF - Solvent flood
GF - Gas flood

Reserve used in forecast
a 1 300

TABLE 22
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
HUSKY OIL PIPELINE (HEAVY CRUDE OIL)

Pool	Established Reserves 103 m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Lloydminster SPC&GPA	1 250	365	100	93	85	77	71	65	60	56	52	49	35	-
Lloydminster SP&GP C&D P&WF	3 630	1 492	280	264	240	220	202	186	172	159	148	138	100	76
Viking Kinsella Wain. B P&WF	4 550a	2 852	1 340	1 177	976	817	688	584	499	429	371	322	170	98
Wainwright Wainwright & Spky A P&WF	9 010b	2 339	1 110	937	813	708	620	545	482	427	380	339	200	126
Wildmere Lloydminster A	1 950	1 368	260	260	260	260	260	255	233	213	196	181	124	89
Others	3 822	2 043	888	829	721	631	556	492	438	391	351	316	-	-
Total	24 212	10 459	3 978	3 560	3 095	2 713	2 397	2 127	1 884	1 675	1 498	1 345	629	389

Reserve Used in Forecast
a 5 010
b 9 910

Recovery Mechanism Abbreviation Used:
WF - Waterflood
SF - Solvent flood
GF - Gas flood

TABLE 23
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
IMPERIAL PIPELINE CO. - ELLERSLIE (HEAVY CRUDE OIL)

Pool	Established Reserves 103 m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Alexander Wabamun C	63	60	3	3	3	3	3	3	3	3	3	3	3	3

TABLE 24
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
MURPHY OIL COMPANY LTD. (HEAVY CRUDE OIL)

Pool	Established Reserves 103 m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Others	1 527	656	150	150	150	150	150	150	150	150	150	137	-	-

TABLE 25
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
PEACE PIPE LINE LTD. (HEAVY CRUDE OIL)

Pool	Established Reserves 103 m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Others	175	106	29	26	23	21	19	17	15	14	12	11	7	5

TABLE 26
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
PEMBINA PIPELINE LTD. (HEAVY CRUDE OIL)

Pool	Established Reserves 103 m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Bigoray Pekisko A	62a	24	33	29	24	21	17	15	12	11	9	8	4	2

Reserve Used in Forecast
a - 120

TABLE 27
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
RANGELAND PIPE LINE COMPANY LTD. (HEAVY CRUDE OIL)

Pool	Established Reserves 103 m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Others	125	83	12	12	12	12	12	12	12	12	12	12	12	8

TABLE 28
SUMMARY OF FORECAST OF PIPELINE SYSTEM PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM ESTABLISHED REMAINING RESERVES
AS OF 31 DECEMBER 1979 FOR
TANK CAR AND TRUCK (HEAVY CRUDE OIL)

Pool	Established Reserves 103 m3		Productive Capacity m3/d											
	Initial	Remaining	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1994	1999
Cessford Basal Col. A	1 780	242	100	100	97	87	78	71	64	58	-	-	-	-
Cessford Mannville C	1 890	693	385	294	234	188	153	126	104	88	74	63	-	-
Glenevis Banff	1 150a	133	100	88	79	72	65	59	53	49	44	41	27	18
Others	2 995	1 553	370	370	370	370	370	370	370	359	321	288	-	-
Undefined and Confidential	1 000	675	100	100	100	100	100	100	100	100	100	100	69	44
Total	8 815	3 296	1 055	952	880	817	766	726	691	654	539	492	96	62

Reserve Used in Forecast
a 1 380